Estimating the Impact of State Tax and Incentive Policies on the Cost of Wind Development in the West

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Abstract

Wind development may be a significant potential source of development and economic diversification in the rural western United States, especially given federal clean energy incentives. Local tax environments can affect which regions successfully attract wind investment due to their effect on developers' costs. Estimates of the tax elasticity of wind development are undeveloped in academic and policy literature, and policy design often occurs without any estimate of their potential impact on development. To address these issues, we develop a detailed model describing the financial structure of typical utility-scale wind development to determine how changes in local and state policies concerning wind energy affect developers' costs across the states in the Western Electricity Coordinating Council (WECC) region. Previous estimates of the effects of tax and incentive policy typically use econometric methods to determine if they have discernible effects *ex-post, but this study focuses on a description of the capital structure of a wind facility to understand how taxation and other policies may affect wind development incentives through cost ex-ante*. This understanding is necessary to develop incentive strategies that minimize competitive development tradeoffs. A comparative analysis of state-specific development costs is conducted using current state and federal wind-development incentives as of Spring 2023. Results resolve some contradictions and ambiguities in previous econometric studies concerning impacts of state incentive policies on wind development. They are also consistent with current development patterns in western states, suggesting comparative development costs are essential drivers of current developers' location choices across states.

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Introduction:

Wind generation capacity has expanded significantly over the past two decades (see Figure 1), growing over 20% annually for 25 years (DoE, 2023). High growth rates are anticipated to continue through the early part of the next decade.[i] One reason for this growth is the dramatic decline in wind technology costs. Lazard (2023) estimates median unsubsidized wind generation costs fell by 72% between 2009 and 2021 (see Figure 2), making new wind generation less costly than new fossil fuel generation and even most existing and fully depreciated fossil fuel generation (Lazard, 2023; Solomon et al., 2023).

Wind energy offers a major economic development opportunity for many rural communities nationwide. Recent federal programs such as the Inflation Reduction Act (IRA) specifically target rural areas of the United States where wind development can create new sources of economic growth and tax revenue and aid in the transition from legacy fuels. For fossil-energy-producing western and midwestern states, wind development may also promote more resilient economies and local government revenues by untying both from volatile energy sector commodity prices (see, for example, Brown et al., 2012; ENDOW, 2018; New Mexico, 2015).

Wind development creates both short- and long-term economic benefits. Short-term benefits accrue to local communities during wind facility construction through demand for construction materials, labor, and other local goods and services. Long-term, wind facilities create additional local employment and demand for materials, equipment, and services through continued operation and maintenance. Local public revenues may be enhanced through new property, sales, income, other taxes, or payments in lieu of taxes (Slattery et al., 2011; Brown et al., 2012; Black et al., 2014; Godby et al., 2018).[ii]

Wind generation, however, also creates local costs. Expansive land use may lead to ecological, cultural, aesthetic, and resource costs (Leung & Yang, 2012; Rand & Hoen, 2017). Nearby wind developments may also affect local property values (Hoen et al., 2015). Increased employment and economic activity caused by wind development may also increase demand for local services, requiring additional revenues to maintain service quality.

Economic benefits and costs and opposing tax policy incentives pose a tradeoff to communities considering wind development (Godby et al., 2018). Reducing the tax burden to encourage wind development may reap economic benefits – even though benefits are often private and greatest in the short term. Local public and non-pecuniary costs and externalities, however, may encourage taxing wind generation activities, especially when power is exported. Such taxation offers a means of exporting local costs to the end-users. Taxing wind generation activities may also recover some revenues that may disappear during the current energy transition. Increased taxes, however, may also harm regional competitiveness in attracting wind investment.

Local tax environments can affect which regions attract wind investment due to their effect on developers' costs. In some cases, by changing tax policy, it may even be possible for a state to increase its attractiveness for development by reducing costs, while also increasing fiscal revenues, thereby avoiding a development/taxation tradeoff altogether. Optimally, states considering incentive programs for wind development would understand how different taxation decisions affect costs and location decisions and create advantages or disadvantages in attracting economic development. Estimates of the tax elasticity of wind development are undeveloped in the literature and, to our knowledge, no comprehensive studies of comparative development costs in the presence of state incentives currently exist. Policy changes concerning taxation therefore occur without estimating their potential impact on development. Absent such tax elasticity estimates, comparative estimates of regional wind development costs and how they may be affected by tax policy may be helpful to policymakers but are very limited in academic literature.[iii]

To address this need, we develop a detailed model describing the financial structure of typical utility-scale wind development to determine how changes in local and state taxation and incentive policies affect developers' costs across states in the Western Electricity Coordinating Council (WECC) region.[iv] Unlike previous studies that attempt to discern the effects of tax and incentive policy on wind development *ex-post*, this study focuses on a description of the capital structure of a wind facility to understand how taxation and other policies may affect wind development incentives through costs *ex-ante*. A comparative analysis of state-specific development costs is then conducted using current state and federal tax laws and wind-development incentives as they were written in Spring 2023. Furthermore, within a state, the effects of different taxes, subsidies, or other financial incentives can be evaluated to determine which ones influence cost most. Understanding this may allow states to optimize tax decisions affecting the potential tradeoff between financially incentivizing development and total lifetime tax revenues from such projects, minimizing competitive development tradeoffs.

2. Previous Literature and WECC Wind Development Background

Prior work on the determinants of U.S. renewable energy development has often focused on national policy incentive impacts on wind development, finding that federal investment and production tax credits have been effective and impactful (e.g. Metcalfe, 2010; Hitaj, 2012). State-specific policy effects have been more challenging to identify, though a consensus in the literature finds demand-side mandates such as renewable portfolio standards (RPS) positively influence wind deployment (Menz & Vachon, 2006; Carley, 2006; Shrimali et al., 2015; Pinkey et al., 2023).[v, vi] Identifying the effects of cost-impacting policies has been difficult, with findings showing mixed results based on econometric specification and data definition. Bird et al. (2005) find that property and sales tax exemptions may be influential, though they conclude that they may not stimulate new wind development alone. Menz and Vachon (2006) did not find public benefits funding to significantly influence wind generation development. Carley (2009) addressed some limitations in Menz and Vachon's methodology to find that state taxes and subsidies were important in determining wind development across 39 states from 1998-2003. Hitaj (2013) used econometric methods to quantify the impact of incentives on county-level wind capacity additions nationally from 1998-2007. She found financial incentives, corporate tax credits, sales tax incentives, and production incentives had positive, significant effects on wind development, but property tax effects could not be identified.[vii] On average, sales and corporate tax credits had similar impacts per dollar spent, while production incentives were about 2.5 times more cost-effective.

Overall, econometric studies consistently find that RPS are effective in driving wind development but have mixed results in identifying the impacts of specific state incentive policies. This is likely due to the difficulty in capturing comparative detail in state policies using econometric methods. As Carley (2011) notes,

> *The energy policy literature contains few analyses that explore the effects or effectiveness beyond this general understanding of the pros and cons of state tax incentives. Tax incentives are likely under-researched because of the immense variation in their design across locations, which makes empirical evaluations of their effects difficult. Additionally, tax incentives are often implemented in conjunction with other instruments, which makes it difficult to tease out the effects of one instrument from the effects of the other in empirical evaluations.* (pg. 277)

Most existing literature is also now dated, largely considering time-periods when the cost of wind technology was not competitive with other forms of electricity generation, and therefore mandated policies such as RPS may have been much more impactful. Later econometric studies partially address this criticism but still find the general results of previous studies. For example, Pinky et al. (2023) found a strongly positive RPS impact on wind capacity using a county-level spatial panel analysis from 2009 to 2019. The effects of financial incentives were weaker, with sales taxes not significantly affecting wind capacity. Property taxes, however, had a significantly positive impact, confirming an earlier finding in Shrimali et al., 2015. Still, conclusions regarding RPS and other renewable energy mandates may not generalize to the present day as wind energy only reached cost competitiveness late in their study period (see Figure 2). Recent efforts have also not addressed Carley's (2011) criticisms.[viii]

Given the caveats above, existing studies suggest that state financial incentives can meaningfully affect wind development, but results are unspecific and contradictory regarding which types of incentives may be most effective. Since they do not account for the specific details of state tax and subsidy policies, these studies ignore or are silent on how specific tax and other incentives affect development costs. Such consideration is necessary for inferences regarding the effectiveness of different incentives for wind development.

An alternative approach is to model the comparative cost of wind development across states. Such models can describe how tax incentives affect the costs and revenues of a wind project, but there is a paucity in the literature of such efforts. Haggerty et al. (2014) developed a limited cost comparison between 17 counties that included all WECC states, to assess how differing property tax policies affect project profitability on identical hypothetical wind farms. Because their focus was not on the costs to wind developers for different tax and incentive regimes across counties and states but instead the local revenue impacts for competitive property tax decisions, their results do not describe how differences in tax policy affect the total development costs in each location.

Patterns of early wind development are consistent with the hypothesis that they were driven by RPS and other mandates, while more recent development may be driven by cost, which is affected by wind resources and state incentives. Figure 3 shows total wind generation capacity for each WECC state by vintage, while Figure 4 shows existing and planned wind generation capacity. Older generation capacity is concentrated in CA, OR, and WA – early adopters of RPS – while newer and planned capacity is concentrated in states with the highest wind generation capacity factors: WY, MT, NM, and CO, as identified in Figures 5 and 6.

Figures 5 and 6 show average capacity factors have from 2019 to 2022 for all facilities built since 1998 and for all facilities five years old or newer.[ix] Comparison suggests how improvements in technology may play a role in shifting new wind development away from west coast states to eastern WECC states, and a reason wind costs per megawatt-hour (MWh) generated have declined. Because wind facilities are highly capital intensive and have low variable costs, average cost measures fall for wind generation as productivity improves. Technology has improved generation performance across all WECC states, as shown by comparing older and newer facilities. The changing pattern in wind development location supports potential wind capacity factors as one of the most important determinants of recent wind development, as highlighted in more recent studies (e.g. Schumacher and Yang, 2018).

Against this background, rural eastern states in the WECC with good wind resources now face an opportunity to utilize energy-based economic development by expanding wind generation capacity

(Carley et al., 2011; Godby et al., 2018). Figures 4, 5, and 6 suggest the four eastern WECC states with the best wind resources have become close competitors for wind development. Most recent developments in New Mexico, Colorado, Wyoming, and Montana use excellent wind resources to export power to more populous regions in the West.[x] Where transmission capacity is a limiting factor, projects use economies of scale to reduce the unit cost of adding new transmission infrastructure.[xi] For example, the SunZia Project in New Mexico and the Chokecherry and Sierra Madre project in Wyoming will be two of the largest wind facilities in the world when completed. Both include costly transmission line projects for exporting power to distant markets.[xii] As the energy transition continues and targeted renewable energy support programs like those in the IRA and the Infrastructure Investment and Jobs Act (IIJA) are enacted, efforts to attract wind development by states are likely to become more competitive, especially among states with the highest-quality wind resources. Given their similarity in generation performance, considerations like state and local financial incentives may be important in determining the location of future wind developments across these states. We turn now to a description of federal and state financial (dis)incentives in developing wind generation.

3.0 Federal and State Financial Incentives

A federal investment tax credit (ITC) program has been available for wind developers since 1978, while a production tax credit (PTC) was created in 1992.[xiii] For wind development, the most influential of these has historically been the PTC. First instituted as part of the Energy Policy Act of 1992, these inflation-adjusted tax credits were originally worth $0.015 in 1993 for each kWh of qualifying renewable production ($15 per MWh). Project eligibility for the tax credit is typically based on the year a project begins construction. Since its inception, the PTC program has been renewed eleven times and has expired six times. These stops and starts have caused yearly wind capacity additions to exhibit a boom-bust cycle over time with the availability or expiration of federal PTCs (see DoE, Chapter 2, p. 19, 2015). The recently enacted IRA extended the PTC through 2024, specifying an inflation-adjusted credit of 2.6 cents per kilowatt-hour ($26 per MWh) for the first ten years of electricity generation. The IRA also added a 10% bonus credit for the federal PTC and ITC if (i) domestic content thresholds are met or (ii) facilities are located in fossil fuel-dependent “energy communities” (a 20% bonus is possible).[xiv]

The Federal PTC program is often misunderstood. The tax credit is non-refundable; the user of the tax credit can only apply credits earned from renewable energy production against existing tax liabilities and cannot claim any excess value as a refund. As wind developers often have very little federal income tax liability, the primary value of the federal PTC program has not been the reduction in income taxes payable by wind developers but the ability to use such credits to facilitate tax-equity financing of wind facilities.[xv] Tax-equity financing involves selling future tax credits to investors, who, in return, provide capital funding for wind projects, thus the program's value has primarily been to reduce the cost of project financing for wind developers.[xvi]

States have also offered various incentives to develop wind power within their borders. These programs directly affect a wind facility’s cost. They can come in the form of production incentives offering cash payments based on the amount of electricity output, tax credits that may be refundable or non-refundable, or exemptions (partial or full) from state and local taxes. They may also come as *payment in lieu of taxes* (PILOT) programs. Table 1 summarizes the tax rates and exemptions available among WECC states. Utah is the only western state currently offering a state production tax credit, granting a $3.50 per MWh refundable production tax credit in the first four years of production. Wyoming includes a less common form of tax (dis)incentive policy, utilizing a wind-specific generation tax additional to all other taxes that is unique nationally, charging $1 per MWh of wind-generated electricity.[xvii]

General tax regime differences also may affect wind development incentives if they reduce a project's taxes payable relative to locating in another state. Three states (Wyoming, Nevada, and Washington) do not have corporate income taxes, while Nevada, Oregon, and Washington instead assess a gross receipts tax. Six states have exemptions from corporate income and business taxes applicable to wind development. Montana and Oregon do not assess sales taxes while seven additional states have sales tax exemptions available for wind energy, including two that entirely exempt wind from sales taxes (Colorado and Utah). In contrast, Washington has an exemption from all sales taxes if a project meets specific wage criteria. Additionally, county or local sales taxes can differ from the state level. Table 1 shows where state and average total state and local rates differ.

WECC property taxes differ by county and state and are affected by state-specific exemption policies. Calculation of property taxes on wind facilities may differ from other forms of property, which can also reduce taxes payable. Only four states in the WECC treat property taxes on wind development as they would on any other utility property – California, Utah, Washington, and Wyoming. Arizona and Montana have reduced tax rates on wind energy relative to other generating facilities. Colorado attempts to create parity with fossil fuel facilities by creating a tax factor that adjusts for the greater capital intensity of wind facilities based on a gross revenue approach. Idaho has exempted all property from taxation and has instead instituted a gross receipts tax of 3% in lieu of a property tax. Oregon, Nevada, and New Mexico have negotiated property tax relief often unique to the project and location.

Other financial incentives are also available in two WECC states. Utah allows economic development tax credits in defined areas. New Mexico regularly offers financing for large capital-intensive projects, including wind facilities, using industrial revenue bonds (IRBs). This scheme allows the local county to own and finance the project through its bonding, leasing the project back to the developer, thus allowing the developer to access financing through non-traditional means.[xviii] Using such a program also makes the county a part owner in the project. Because counties are often tax-exempt entities, projects utilizing such funding negotiate property and county sales taxes payable on a case-by-case basis. We refer to this form of incentive as a PILOT program. New Mexico also allows a community development incentive wherein counties may exempt up to 100% of property taxes for 20 years (excluding school district funding or other specific funds).[xix]

Some incentives will be more valuable than others due to their impact on overall project costs and the timing of these costs. For example, wind facilities are highly capital intensive and incentives that reduce total financing costs may be more valuable than tax reductions. Therefore, it is essential to understand the capital structure of a renewable energy facility to understand how financing and different types of taxes affect the overall lifetime cost of the project, especially if the goal in designing tax policy is to attract such development.

The following section describes our modeling framework, which decomposes the various components of cost at a wind facility, including capital, operating, and financing costs, and allows for differences in local and regional cost conditions and resource quality, as well as federal and state taxes and incentives to determine the relative cost competitiveness of wind generation in each WECC state. Optimally, states considering incentive programs for wind development will understand how different incentives affect costs and location decisions. To our knowledge, no comprehensive studies of comparative development costs in the presence of state incentives exist in the academic literature.

4. Modeling Framework

The most used energy development cost metric is the levelized energy cost or LCOE. In principle, the LCOE sums all expected costs over the lifetime of a generator and compares them to expected lifetime output to compute the average cost of each unit of electricity produced, expressed in dollars per MWh.[xx] We develop a levelized cost estimate, which we refer to as the *average cost of energy* (ACOE) for each of the eleven WECC states assuming an identical wind facility.[xxi] Tax and incentive differences across states, as well as wind resource and regional cost differences, are then used to show how they affect states' computed relative cost competitiveness to attract wind energy.[xxii] Given the motivation of this work – comparison of state costs – we focus on relative differences between states and not the absolute values of cost presented. Greater detail and the specific computation logic of the cost model used are described in the Appendix.

Cost calculations like those presented here require a specific description of the financing of wind development, often referred to as its *capital structure*. The capital structure is critically important in identifying how cost results change with input cost and interest rate assumptions and by the types of incentives states offer. Modeling costs in detail allows an understanding of how potential incentives such as tax credits and exemptions affect costs not only through the direct tax cost but also through their impact on financed costs, which can affect the incentive impact on developer choices. Assumptions necessary to calculate the cost estimates are summarized in Tables 2, 3, and 4. Relative construction cost differences by state in Table 2 use U.S. Army Corps of Engineers Civil Works Construction Cost index values (USACE, 2023). Facility component cost assumptions in Table 3 come from government and industry sources, while wind resource assumptions by state are described in Table 4. [xxiii] Tax rates and practices by state use information summarized in Table 1.

We assume an identical 300 MW project for each state in the WECC. The system cost of a project is determined by the overnight cost of the project – the cost of capital and its construction and installation costs. We assume an overnight installed project cost of $1511 per kW, the average cost of capital in western states in 2022 (DOE, 2023) adjusted for regional cost differences (Table 2). The total cost to construct a wind facility is also affected by sales taxes, where most sales taxes over the life of a facility are paid during procurement and construction. We assume a conservative estimate of two-thirds (67 percent) of system costs are taxed.[xxiv]

Once system costs are known, financing costs are computed. We assume a specific share of total system costs are financed by traditional debt. An amortized payment is computed based on the assumed traditional debt interest rate. The term on this debt is assumed to be two years less than the system life of the project, allowing for a common industry practice of creating a two-year buffer on such debt. The remaining share of system costs is then financed by the sale of federal production tax credits the project will earn (tax equity) and direct equity. The amount of tax equity sold is computed by calculating the production tax credits the plant is expected to create over its lifetime, given state wind resource assumptions and the assumed tax equity rate of return. Any remaining project financing is then assumed to be funded by direct equity, which earns an assumed rate of return. The sum of financing payments on traditional debt and direct equity are then used to define the total annual finance costs of the project. Assumed rates of return, system costs, and project lifetime are described in Table 3.

State-specific annual operating costs (OPEX) are computed as the sum of annual O&M costs, the annual costs of financing a sinking fund to cover assumed decommissioning, and the annual insurance costs. The average cost of energy before taxes expressed in dollars per MWh is then computed by summing total annual operating, system, and finance costs over the project's life and dividing by the expected lifetime electricity production of the facility using capacity, capacity factor, and production degradation assumptions. The resulting computation is the pre-tax breakeven annual cost per MWh of output necessary to create the assumed rate of return on direct equity while covering all other costs. The pre-tax cost methodology is conceptually similar to industry estimates of levelized cost (e.g. Lazard, 2023), however, we include greater cost detail on insurance, decommissioning, and financing.

Once pre-tax ACOE is determined, property tax costs are computed. Annual property taxes are estimated for each state using the state-specific tax rules. For Wyoming only, production taxes are assessed using estimated electricity output in that year using the state's capacity factor and degradation assumptions. Property and production taxes are then added to the pre-tax ACOE value. To ensure the assumed rate of return payable to direct equity is achieved, we assume all electricity produced is sold at a price equal to post-tax ACOE. To calculate the post-tax ACOE, income and gross receipts taxes and resulting post-tax ACOE is calculated iteratively as described in the Appendix until convergence to a constant payment is defined.

5. Estimated State Tax Policy Impacts and Potential Development Tradeoffs

Using the methodology, cost, and state policy assumptions described previously, ACOE estimates for WECC states are presented in Figure 7 and Tables 5 and 6. ACOE values are presented as a range for each state. The first state ACOE computed uses an identical 35% capacity factor and assumes construction costs are identical across states. Under these conditions, the only causes of cost variation by state are the differences in incentives and taxes. This computation typically defines the high end of the range of ACOE for each state. The lower end of the range is usually computed assuming state-specific capacity factors, regional construction cost differences, and state-specific incentive and tax policies.[xxv] Two states have multiple entries. The estimated range of ACOE for Wyoming is shown for current tax and incentive policies and two hypothetical tax policies explained below. New Mexico appears twice in the chart as projects may or may not take advantage of IRBs and associated payments in lieu of taxes or tax payments at negotiated rates.[xxvi]

Comparing states, the lowest ACOE occurs for New Mexico when IRBs are used. The next three lowest-cost states are estimated to be Montana, Colorado, and Wyoming, where results are very similar, with only a 4 percent difference between Montana and Wyoming when current taxes and incentives are considered. The lowest ACOE estimates of the remaining WECC states are significantly higher than those of the four lowest-cost states. Results also verify some conclusions in the previous literature. First, the relative importance of resource quality is apparent. The similarity of capacity factors across the four lowest-cost states indicates that none currently has a significant resource advantage. Among the lowest cost states in Fig. 7, another significant factor not considered in previous literature is regional labor and construction costs. The four lowest-cost states have regional cost index values varying from 0.94 to 0.90, as shown in Table 2. These two factors - resource, and comparative construction costs - result in the four eastern WECC states having the lowest estimated development costs and make a compelling argument for understanding patterns of recent and future development shown in Figures 3 and 4.

Results also suggest how certain tax and incentive differences across these states can determine a state's cost competitiveness. The impact of incentives and tax reductions on ACOE across WECC states are shown in Tables 5 and 6 when wind resources and regional costs are considered and when capacity factor and regional costs are held constant, respectively. Figure 8 summarizes these state tax burden outcomes. When ranked considering potential resource and construction cost differences, Colorado has the lowest tax burden after incentives of any state. Utah and Arizona rank second and fourth, respectively, reflecting the higher value of incentives in these states. Montana ranks third, primarily due to incentives and the lack of a sales tax, while Oregon ranks fifth due to the low taxes and moderate incentives. Following these states are New Mexico and Wyoming, which are instructive for different reasons. Both have identical assumed wind resources, while New Mexico has regional costs estimated to be 3.2 percent lower than Wyoming's. While New Mexico's tax burden is $0.58 less than Wyoming's, its estimated ACOE is $4.51 (15.8 percent) less. New Mexico's primary incentive is, in fact, not a tax or incentive policy but rather the ability to use bonding, which results in a significantly lower system cost due primarily to the reduction in project financing costs this opportunity creates. New Mexico's ACOE is much closer to Montana, Colorado, and Wyoming's costs without such bonding.

From the various forms of taxation across states in the WECC, a logical question arises as to which forms of taxation lead to the least tradeoff between economic development and revenue. There is a long literature on how specific taxes affect economic development and whether some taxes are more important than others. The literature on such questions concerning development is generally inconsistent (see Gale et al., 2015). Hitaj (2013) is the only paper addressing this question in the context of wind development. We refer to the results presented here and Hitaj's results to consider which types of taxes may be most important when considering state wind development policies.

From Tables 5 and 6, one tax difference among states that makes little difference to overall costs is the presence or absence of a state income tax for wind developments. While lower or a lack of income taxes is often considered a potential economic development advantage for some states, this is not true across industries. In capital-intensive ones like wind generation, the income tax burden of such facilities is comparatively small relative to other taxes due to high interest and depreciation costs that can be deducted. Therefore, states like Nevada, Washington, and Wyoming in the WECC see little advantage in attracting wind development by having no income taxes.[xxvii]

While Nevada and Washington have no income tax, they, New Mexico, and Idaho do assess a gross receipts tax. This alternative form of tax can potentially capture greater revenues from wind generation than an income tax because such policies usually lack the sorts of deductions against taxes payable that income taxes allow. While such a tax can increase revenues for wind development over an income tax, as is apparent in Tables 5 and 6, it also increases the cost of wind generation, potentially deterring such development.

As noted previously, sales taxes are primarily paid during procurement and construction, which are assumed to be financed, and therefore affect the after-tax system costs of a project and its finance costs. Given these impacts, the benefit of sales tax reductions on wind development may be larger than for exemptions on other taxes, specifically property taxes, the most common form of taxation on wind across WECC states. Explicitly modeling sales tax effects may explain why property tax incentive effects were more difficult to identify than sales tax effects in previous literature.

Another common practice nationally has been the use of a production incentive to encourage wind development. Hitaj (2013) found this to be the most potent tax incentive a state can offer, finding that a $10 per MWh incentive could increase wind capacity by 20 percent annually.[xxviii] In the WECC area, states have no such incentives, however, Wyoming uses a wind production tax to raise revenue, charging $1 per MWh of production. If Hitaj's results hold for Wyoming, the $1 per MWh would reduce capacity additions by 2 percent annually. Wyoming has recently considered increasing its production tax on wind from $1 per MWh to as high as $5.00 per MWh (see Godby et al. 2018). Hitaj's results would suggest this would significantly decrease potential wind development in the state.

The impact of such a tax increase on Wyoming's relative cost-competitiveness can be seen in Tables 5 and 6, as well as Figures 7 and 8. Wyoming's ACOE would rise by 11.7 percent, assuming state-specific capacity factors and regional costs, though it would remain fourth lowest in the WECC. Considering state-specific potential capacity factors and cost differences, the ACOE in Wyoming with the increased tax would be almost 33 percent higher than New Mexico's (when IRBs are used) and over 17 percent higher than Montana's and 15 percent higher than Colorado's. Tables 5 and 6 more clearly demonstrate the impact of such a tax increase. The cost of the wind excise tax now increases from $0.84 per MWh to $4.20 and more than doubles the total tax burden per MWh of wind-generated electricity in Wyoming. Consistent with Hitaj's earlier estimates, these comparative results also suggest that such a cost increase could significantly impact wind development in Wyoming relative to other states, specifically Colorado and Montana.

Another disadvantage of such a tax increase in terms of state competitiveness is the fixed nature of the tax burden. Over time, wind costs have been declining on a per MWh basis (see Figure 2). This trend is expected to continue. When taxes are assessed on a percentage basis, as with income, gross receipts, property, and sales taxes, taxes payable will also decline in a declining-cost environment. Wyoming's fixed production-based tax, however, imposes a non-declining burden, making the state less cost competitive over time in a declining-cost environment. Given these results, states looking to increase tax revenues from wind development should consider production taxes very carefully.

Comparison of tax policy costs across states can be instructive when trying to increase economic development. As Raimi et al. (2023) estimate, four states (Wyoming, New Mexico, Montana, and Colorado) in the WECC rank among the top fossil-fuel revenue-dependent states nationally and may be most fiscally impacted by the ongoing energy transition. Wyoming's dependence is the highest in the country at 54 percent, while New Mexico's ranks fourth at 15 percent. We focus on Wyoming and New Mexico as instructive examples of how local state incentive and tax decisions could affect the cost competitiveness of a state attempting to attract wind development and additional fiscal revenue.

Combining strategies like New Mexico's IRB policy with increased taxes may allow a state to maintain cost competitiveness to attract wind development while also providing an opportunity to increase tax revenues earned per MWh. These revenues would be in addition to tax revenues from any additional economic activity wind development may spur through multiplier effects (see Godby et al., 2018). When IRBs are used, New Mexico's total tax revenues per MWh are $0.58 lower than Wyoming's, yet its overall ACOE is $4.51 lower. The primary reason for the cost advantage New Mexico experiences over Wyoming is the impact of their bonding policy on the finance cost portion of ACOE, which is less than half of Wyoming's.[xxix]

Alternatively, Wyoming's tax policies are less consistent with understood mechanisms that avoid deterring wind development while also improving state revenues. Over half of Wyoming's tax revenues per MWh rely on production and sales taxes, which have been argued in previous research to have larger negative impacts on economic development. This suggests that Wyoming might improve its wind development competitiveness while protecting tax revenues by changing its composition of taxes. To test this, we explore an alternative hypothetical tax policy.

In 2009, Wyoming repealed its sales tax exemption on wind. Currently, the sales tax on new wind development is estimated to be $0.63 per MWh, as shown in Figure 8 and Table 5. This does not include the financing cost required to pay these taxes during construction and before operations begin. Wyoming also charges a wind production tax, which costs $0.84 per MWh.[xxx] With existing property taxes, the total cost of taxes for new wind development in Wyoming is $2.83 per megawatt hour. Given previous studies, the production and sales taxes Wyoming charges could create a greater disincentive to development in Wyoming than using property, gross receipts, or income taxes.

As an alternative tax policy experiment, consider how estimated ACOE would be affected if the state's sales tax exemption were reinstated on wind equipment and the current $1 per MWh production tax was rescinded. To replace the lost revenue, consider outcomes if Wyoming assessed a royalty on the value of electricity produced (similar to the impact of a gross receipts tax but the tax is restricted only to wind-generated electricity), an idea Wyoming considered in 2009.[xxxi] Assume a royalty rate of 6.5 percent, consistent with the level Wyoming charges as a royalty on surface coalmining in the state.

Results in Table 7 suggest that with these changes, Wyoming could increase state competitiveness to attract wind development by lowering ACOE while increasing total revenues from wind facility taxation. The effect of the change is to eliminate sales taxes collected during construction and production taxes paid over the project's life, replacing these with a royalty fee of 6.5 percent assessed on the revenues created from electricity sales. Undertaking this policy reduces the ACOE of wind development in Wyoming from $28.50 to $27.67, a reduction of 2.9 percent. The tax change reduces the total cost of electricity over the project's life by over $20.2 million or, on average, over $1 million per year. The change also decreases Wyoming's ACOE to be nearly equal to Colorado's among WECC states. Given previous findings on the drivers of wind development, this change would also potentially improve the state's attractiveness to developers both because of the reduced costs and the fact that past research has found that production incentives (or disincentives like Wyoming's fixed wind production tax) are more robust drivers to development than sales taxes or royalty payments.

When taxes collected per megawatt hour in Wyoming are considered, the total taxes collected rise by over $1.1 million over the project's life, and on a per MWh basis, increase from $2.83 to $2.87 per MWh, or nearly 1.5 percent. Overall, these results show that the traditional development/taxation revenue tradeoff for wind development is avoided - development costs are reduced while total tax revenues are increased. Relative ACOE competitiveness improves because the reduced sales tax burden lowers financing costs by 14 percent. Federal income tax and operating costs are also reduced by 24.7 percent and 3.4 percent, respectively, while the future relative cost effects of a fixed production tax in a declining cost environment are also avoided.

While undiscounted total tax revenues over the project's life are greater under the proposed tax scheme, a potentially more important advantage of the alternative tax policy may be the stream of payments a royalty creates for local policymakers. The annual payments that could be expected would create a reliable income stream for the state and communities affected, lasting the life of the project. Currently, most sales tax revenues from wind projects result in one-time revenue during construction, with the political and revenue management difficulties such lump-sum can create for counties and local governments.

6. Conclusions

Wind development is a significant potential source of development and economic diversification in the rural western United States, especially given newly offered federal clean energy incentives. Since state policy can affect the cost of wind development, states should be cognizant of how tax policy changes can impact relative costs with other states. Results presented here can inform policymakers of the relative development costs across states and may help identify where tax changes can better achieve state goals.

The analysis presented attempts to estimate the impact of local state taxation and incentive policies on the cost of developing wind across the states in the western United States. Using a detailed model describing the financial structure of a utility-scale wind development, we argue that considering a wind development's capital structure is crucial to understanding how different taxation and other policies affect wind development incentives. It can also resolve some contradictions and ambiguities in previous econometric efforts that attempted to determine the impacts of state tax and incentive policies on wind development. Cost estimates derived here are also consistent with current development patterns in western states, suggesting comparative development costs across states are important drivers of current developers' location choices.

Modeling estimates presented here indicate that state incentives can also be important in affecting relative competitiveness among states by reducing the cost of wind development. Cost competitiveness, however, need not occur as a tradeoff with state revenues. Careful design of state tax policies, including altering the composition of taxes, combined with offering other creative policies such as alternative financing in the form of IRBs or similar, can not only reduce the development/fiscal revenue tradeoffs states face in attracting wind development but also may lower the cost of wind development, incentivizing greater economic development. Such opportunities could be particularly appealing to states facing revenue declines from fossil fuels in the ongoing energy transition who wish to stimulate development and/or create new revenues. We demonstrate these ideas through consideration of tax policies in New Mexico and Wyoming as examples. In some cases, as we showed in the case of Wyoming, it may be possible to identify a policy that limits or even avoids such tradeoffs.

Understanding how policy changes could affect the cost of wind development relative to other states is also essential to avoid unintended development impacts. This is especially important when the development elasticity of tax policy changes has yet to be discovered. A benefit of specifically modeling developer costs is the ability to consider holistically how different taxation and incentive choices may impact the tradeoff between wind development and fiscal revenues. Some tax changes affect wind development not only by their direct effect on project tax burdens but also by their impact on other costs, such as financing. Given this, it is important to consider the capital, operating, and tax structure of wind developments to understand how tax policies and incentive changes may impact project costs and a state's attractiveness to wind development. Principles developed here can also be applied to other types of development. Understanding such impacts can allow policymakers to better weigh the tradeoffs of policy or incentive choices under consideration. It also allows them to maximize the effectiveness of taxation policies in attracting development and raising revenues.

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Appendix

The following describes how the cost estimates used to compare the impact of state incentives on wind energy costs across western states are computed. Developing the ACOE for each state begins with defining the system cost of the assumed project. We assume an identical 300 MW project is considered in each of the eleven states in the WECC. For simplicity, we do not consider any additional transmission or integration costs necessary to connect the project to the regional electricity grid. The system cost of a project is determined by the assumed overnight cost of the project – the cost of capital and its construction and installation costs. We assume an overnight installed project cost of $1511 per kW, the average cost of capital in western states in 2022 (DOE, 2023). The overnight cost is then adjusted for regional cost differences using U.S. Army Corps of Engineers Civil Works Construction Cost index values (USACE, 2023), as described in Table 2. The computation of the total cost to construct a wind facility is also affected by sales taxes, where the majority of sales taxes over the life of a facility are paid during procurement and construction. We assume a conservative estimate of two-thirds (67 percent) of system costs are taxed.

Once system costs are known, financing costs are computed. We assume a specific share of total system costs are financed by traditional debt. An amortized payment is computed based on the assumed traditional debt interest rate. The term on this debt is assumed to be two years less than the assumed system life of the project, allowing for a common industry practice of creating a two-year buffer on such debt. The remaining system costs are then financed by the sale of federal production tax credits the project will earn (tax equity) and direct equity. The amount of tax-equity sold is computed by calculating the production tax credits the plant is expected to create over its lifetime (plant capacity x state-specific capacity factor x any assumed degradation of that capacity factor over time x value of the tax credits). The net present value of these credits is then determined, discounted at the assumed tax-equity rate of return. Tax credits are then assumed to be sold at this value to raise the tax-equity portion of the project financing. Any remaining project financing (system costs minus traditional debt raised minus tax-equity raised) is then assumed to be funded by direct equity at an assumed internal rate of return.[xxxii] The sum of financing payments on traditional debt and direct equity are then used to define the total annual finance costs of the project. The values assumed for the share of total system costs financed using traditional debt, rates of return for traditional debt, tax equity, and direct equity, and the life of the project necessary to compute cost estimates are summarized in Table 3.

As shown in Figure A1, state-specific annual operating costs (OPEX) are computed as the sum of annual O&M costs, the annual costs of financing a sinking fund to cover assumed decommissioning costs, and the annual insurance costs. The average cost of energy before taxes expressed in $/MWh is then computed by summing total annual operating and finance costs over the project's life and dividing by the expected lifetime electricity production of the facility using capacity, capacity factor, and production degradation assumptions.[xxxiii] The resulting computation is the pre-tax breakeven annual cost per MWh of output necessary to create the assumed rate of return on direct equity while covering all other costs.

The pre-tax cost methodology outlined here is similar to that used for industry estimates of levelized cost presented in Lazard (2023); however, our degree of detail in modeling costs is greater. Industry estimates typically do not assume a buffer in the payment of traditional debt, nor do they usually include insurance costs, decommissioning costs, and tax impacts on financed costs. Furthermore, "unsubsidized" estimates like those in Lazard (2023) ignore the impact of tax-equity financing utilizing the federal PTC.

Once pre-tax ACOE is determined, property and production taxes are computed in the case of Wyoming. The computations for property and production taxes are described in Figure A2. Annual property taxes are estimated for each state using the state-specific tax rules summarized in Table 1. Total taxes paid over the project's life are computed and converted to a per MWh cost. In the case of Wyoming, the production tax is assessed as a charge per MWh of electricity produced each year using estimated electricity output derived from the project capacity, state capacity factor, and degradation assumptions. After these taxes are computed, property and production taxes are added to the pre-tax ACOE value.

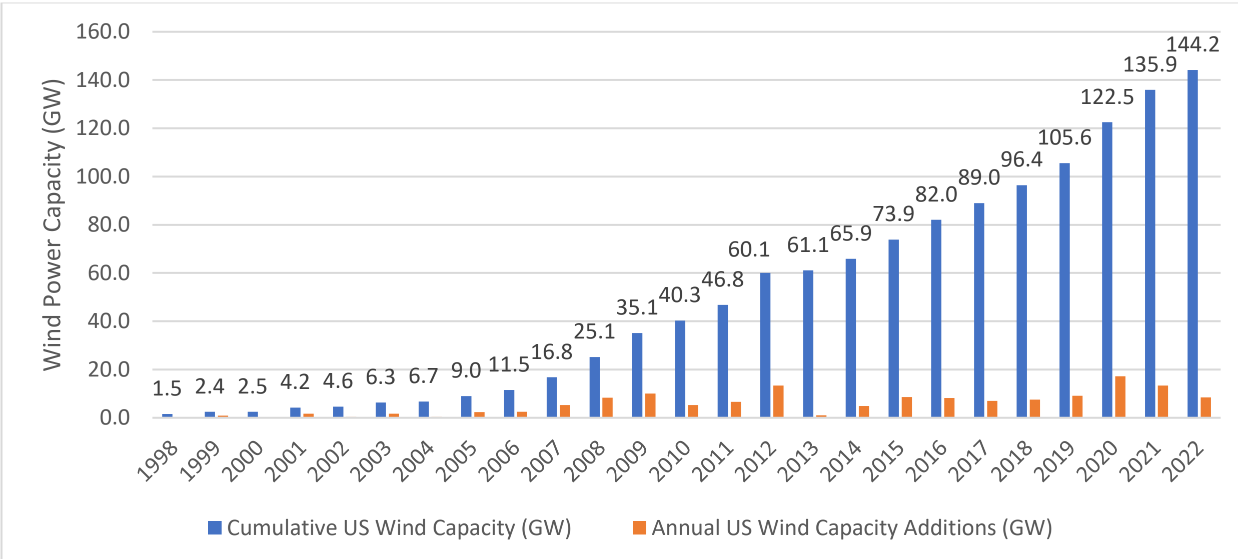
Figures A3 and A4 describe the computation of income and gross receipts taxes. To ensure the assumed rate of return payable to direct equity is achieved, we assume all electricity produced is sold at a price equal to post-tax ACOE. To calculate the post-tax ACOE, income and gross receipts taxes and resulting post-tax ACOE must be calculated iteratively. State and federal income taxes are computed using the ACOE as the sales price to compute annual profits, deducting depreciation, interest paid on traditional debt, and other tax-incentive payments.[xxxiv] Annual income taxes payable are then added to the pre-tax system costs to determine a new ACOE. The computation of income taxes is repeated until convergence is achieved. Gross receipts taxes are handled similarly, with taxes payable on gross sales computed iteratively until convergence to a constant payment. All computations are made using Microsoft Excel using the Solver Add-in.

5.2 Capacity Factors

Table 4 describes the potential gross and net capacity factors used in the analysis.[xxxv] Gross capacity factors (GCF) shown in Column A were determined for the best 5 percent of land areas in each state from the “Cumulative Area vs. Gross Capacity Factor” charts developed by AWS Truepower and NREL, which are publicly available from the U.S. Department of Energy’s WindExchange website.[xxxvi] Since GCF does not include adjustment for reductions in output due to operational considerations or turbine wake, two types of adjustment are made to estimate possible net capacity factors. The GCF in each state is reduced by 9.8 percent in each state to account for constant fixed factors (those that do not change over time) that reduce facility output.[xxxvii] These values are shown in Table 4, Column B. Finally, an annual degradation factor of 0.75 percent is applied to account for reduced turbine performance over time due to blade efficiency reductions and increasing maintenance needs.[xxxviii] As shown in Table 4, Column C, this eventually reduces the capacity factor by an additional 13.3% percent over 20 years.

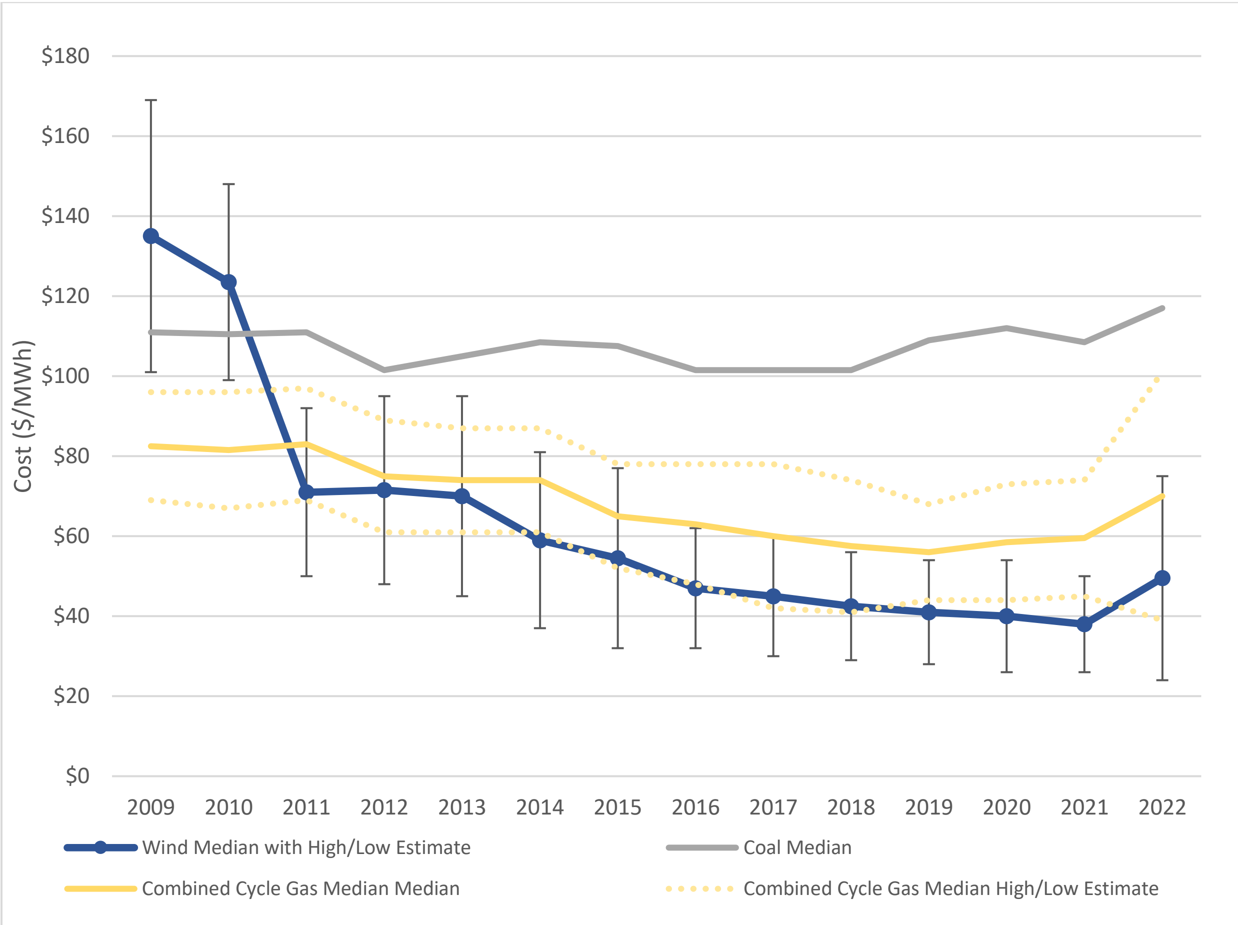
As previously described, there is little difference in either observed capacity factors or estimated potential capacity factors between the top 4 states in Table 6 (NM, WY, MT, and CO); thus, from a wind resource perspective, the western states of the WECC could be considered near competitors, and this suggests that other aspects affecting cost could have significant influence for any developer making a location decision in one of the four states. It is important to note that the cost estimates developed here do not include any additional costs necessary to complete local permitting or transmission development.[xxxix]

Figure 1: US Wind Generation Capacity (GW)



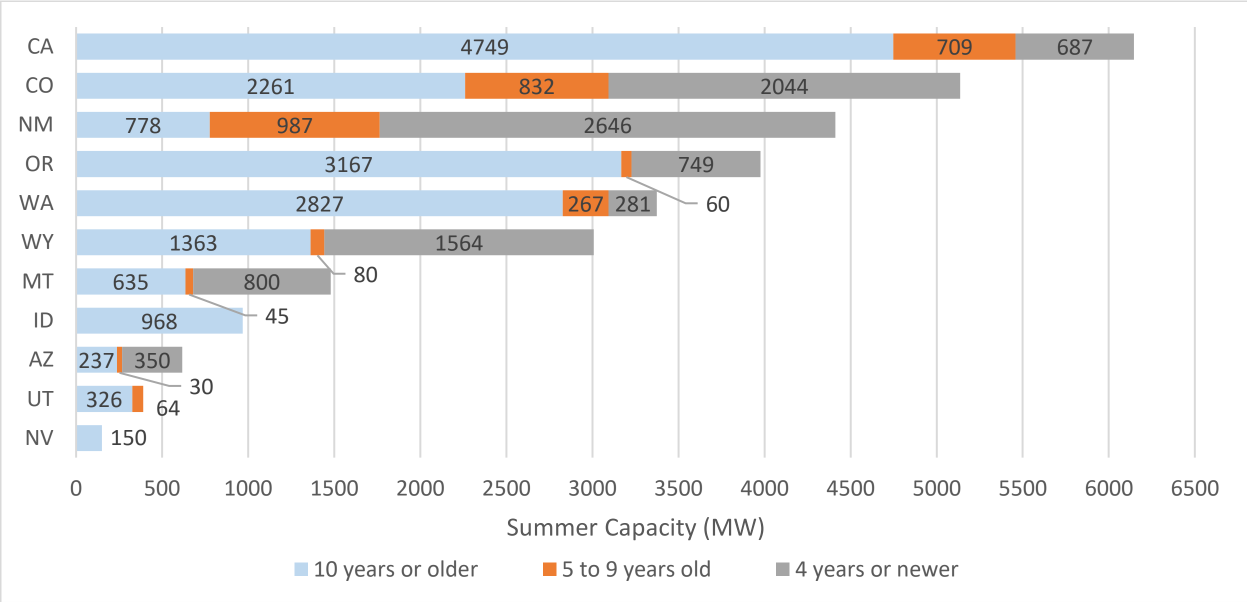
Source: Department of Energy (DoE), 2023.

Figure 2: Estimated Median and High/Low Unsubsidized Wind Levelized Cost, with Comparison to Traditional Sources (2009-2022)



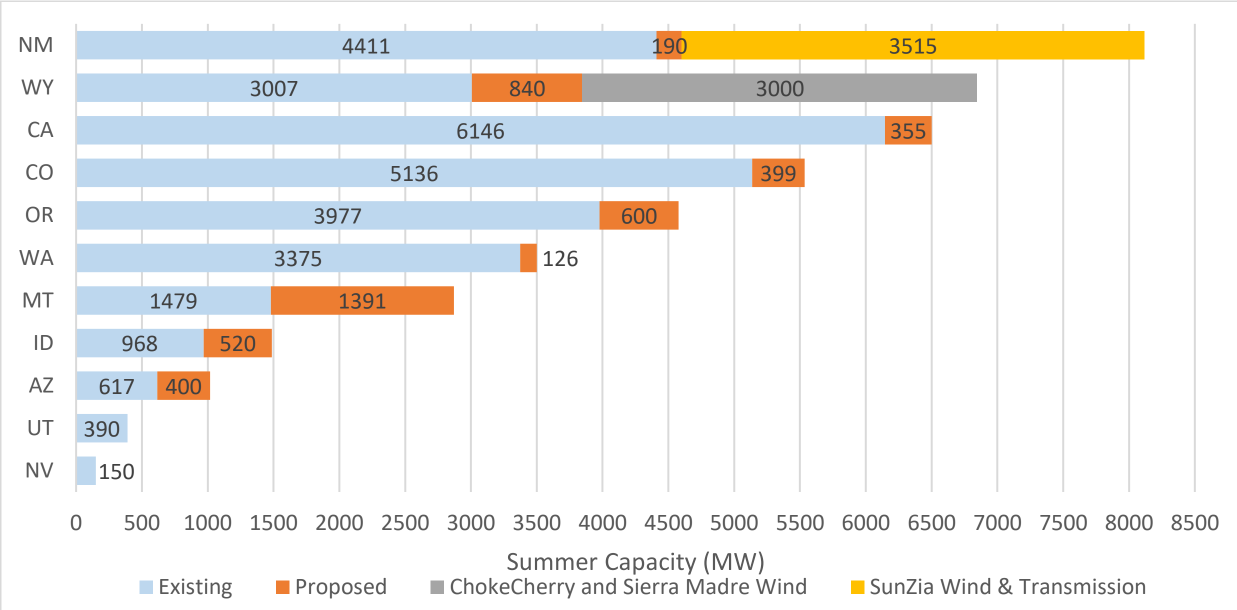
Source: Lazard (2023)

Figure 3: Existing Wind Generation Capacity by Vintage across WECC States



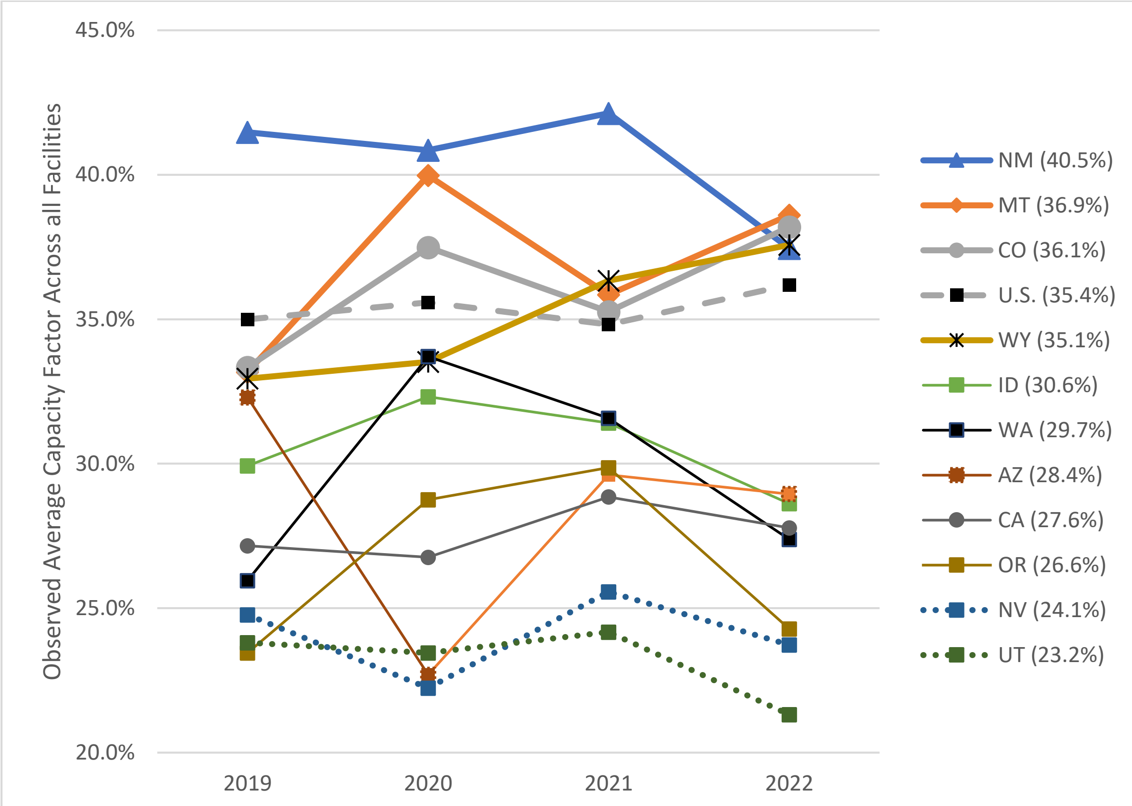
Source: Form EIA-860 Final Data. Release Date: September 19, 2023.

Figure 4: Existing and Planned Wind Generation Development across WECC States



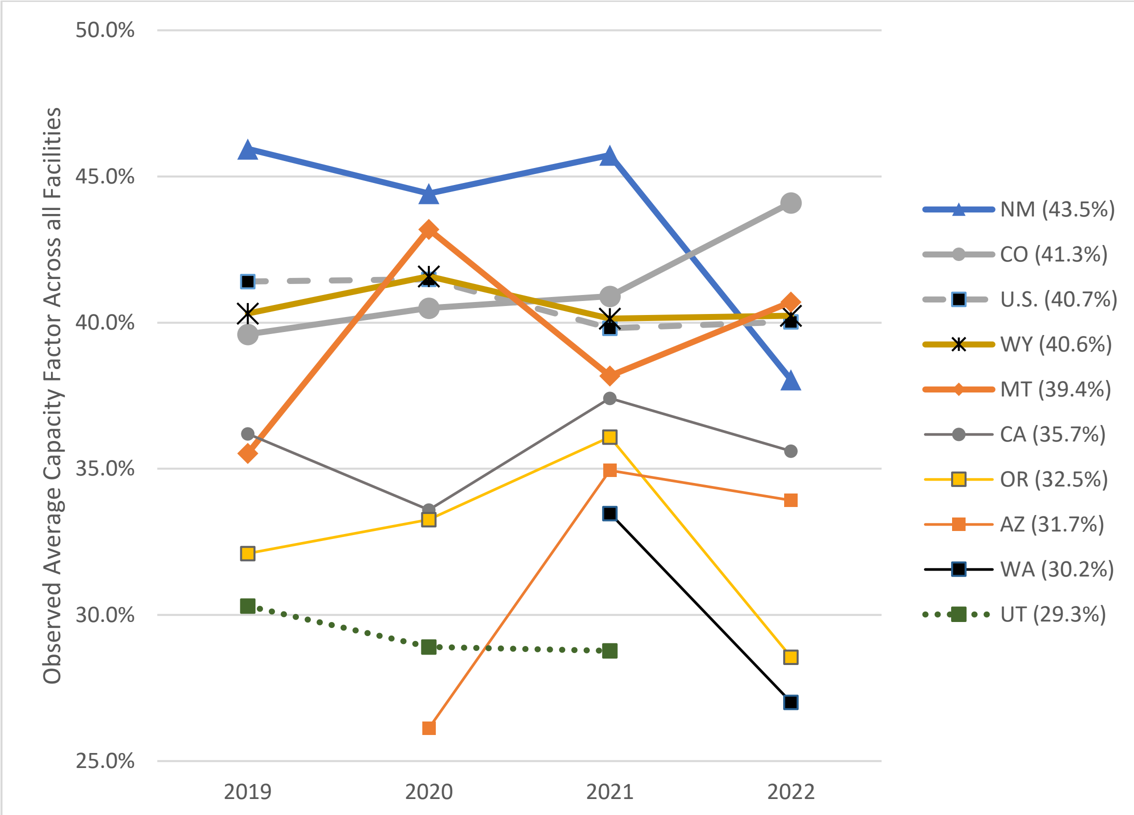
Source: Form EIA-860 Final Data. Release Date: September 19, 2023.

Figure 5: Observed Average Capacity Factors by State – all facilities built since 1998.



Source: Department of Energy, 2023. The parenthetic values indicate the average annual capacity factor achieved by the state over the past four years.

Figure 6: Observed Average Capacity Factors by State – all facilities five years old or newer.



Source: Department of Energy, 2023. The parenthetic values indicate the average annual capacity factor achieved by the state over the past four years.

Figure 7: State Estimates of Wind Generation Average Cost of Energy with Current Taxes/Incentives

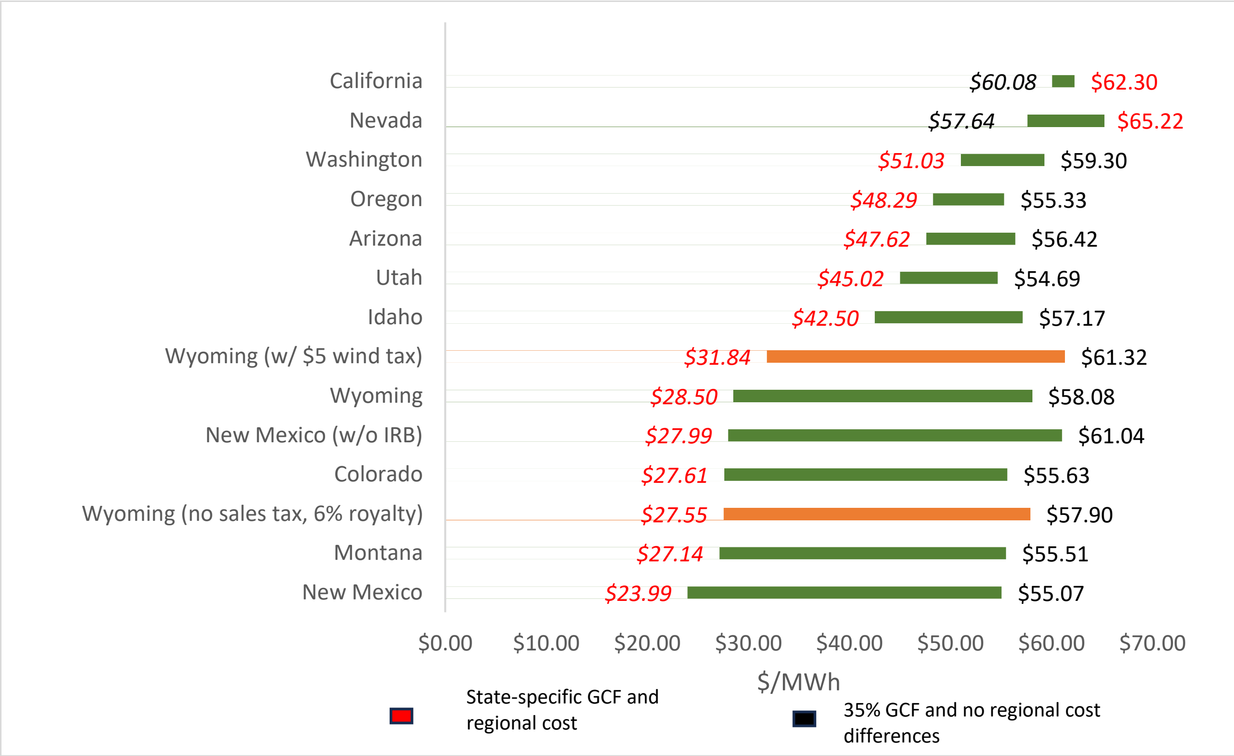


Figure 8: Comparative Tax Burdens on Wind Development by State

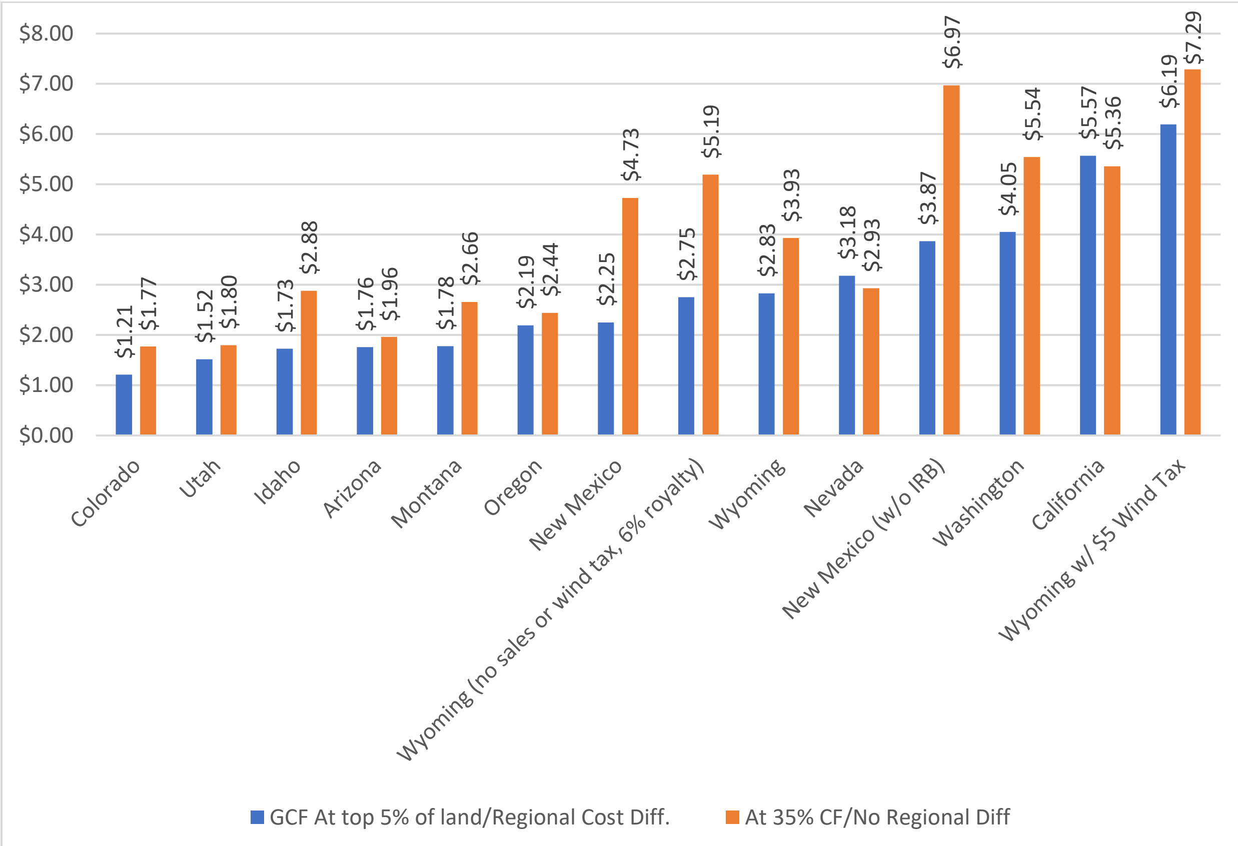
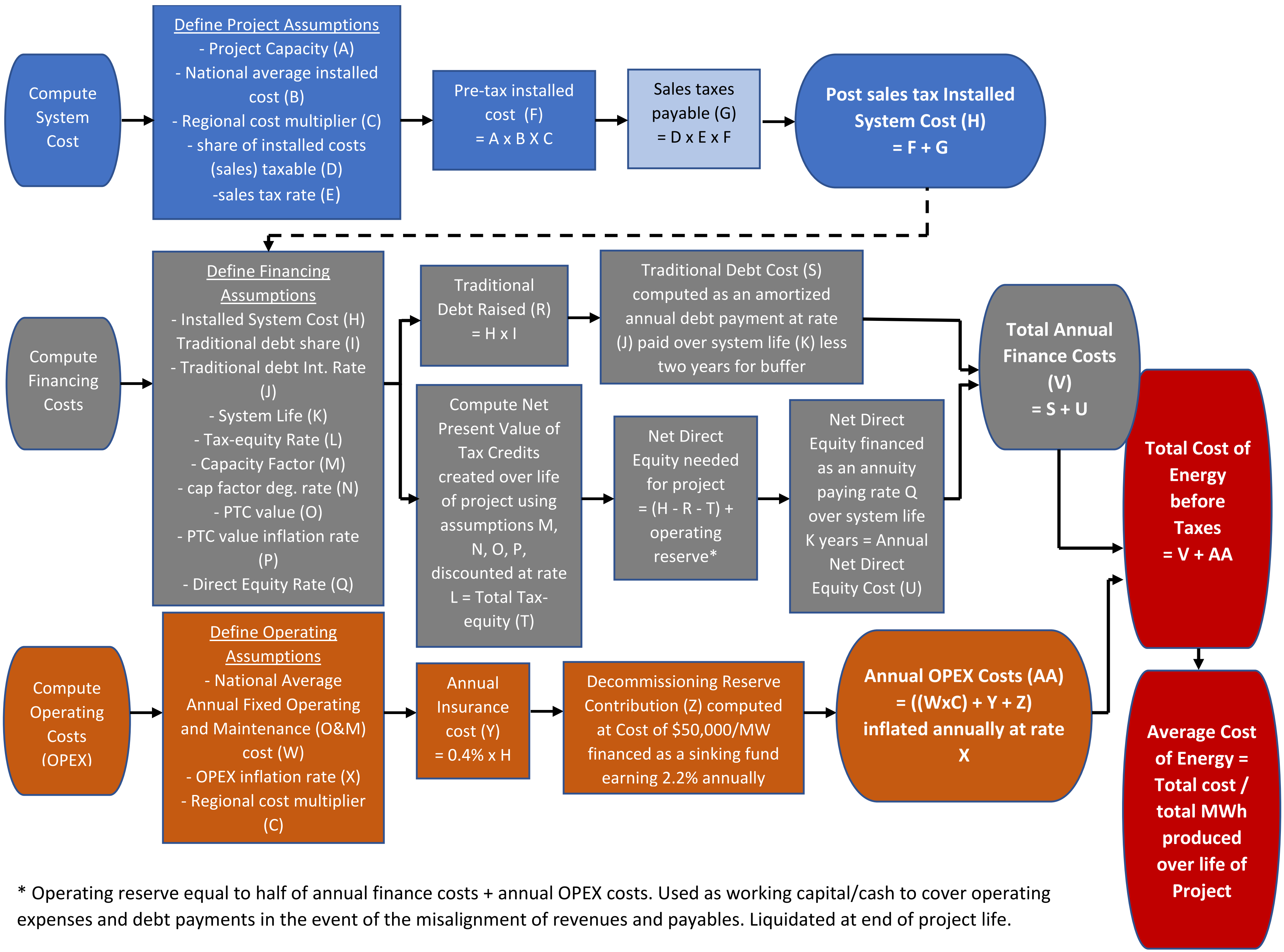


Figure A1: Process of Computing Average Cost of Energy Computation before Income and Wind Taxes



* Operating reserve equal to half of annual finance costs + annual OPEX costs. Used as working capital/cash to cover operating expenses and debt payments in the event of the misalignment of revenues and payables. Liquidated at end of project life.

Figure A2: Property and Wind Tax Cost Computation Processes

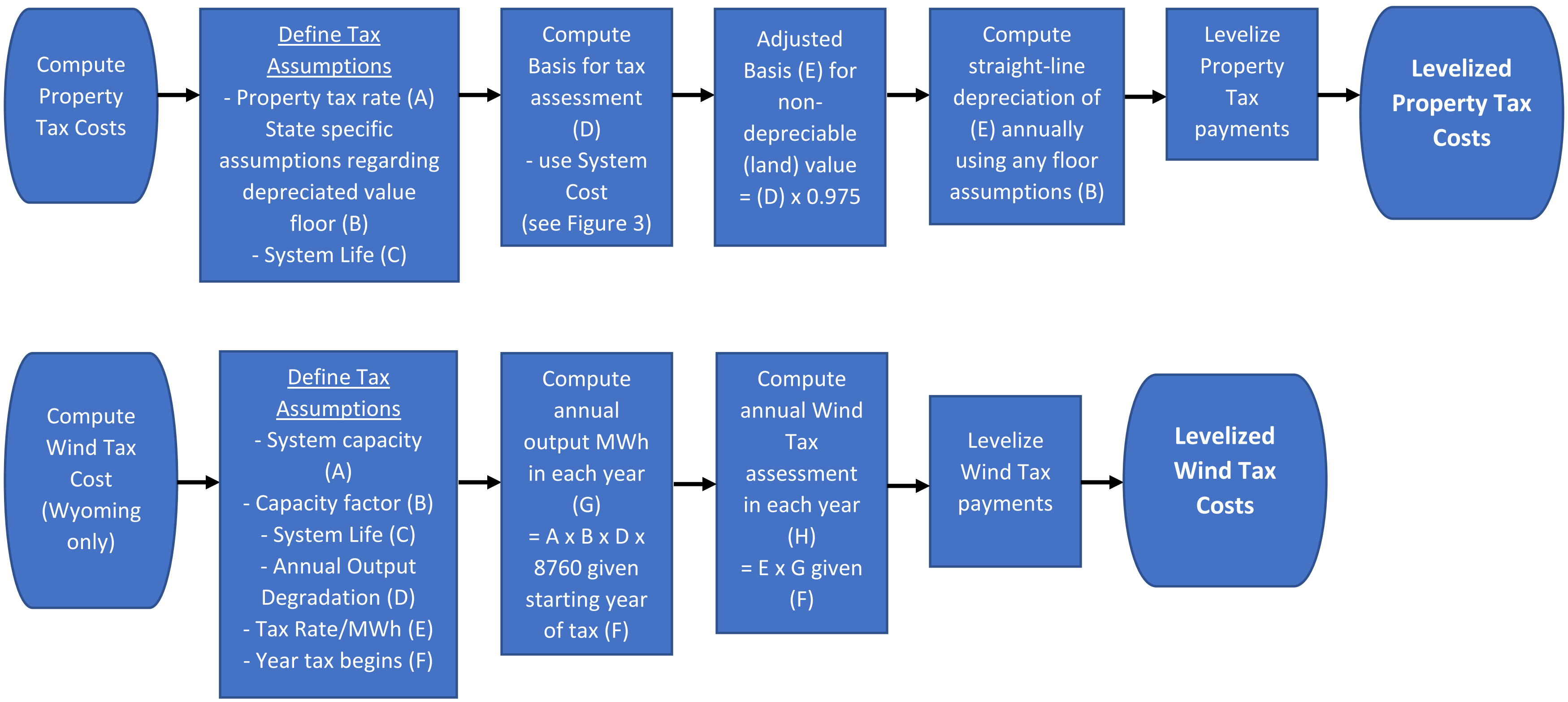


Figure A3: Income Tax Cost (Federal and State) Computation

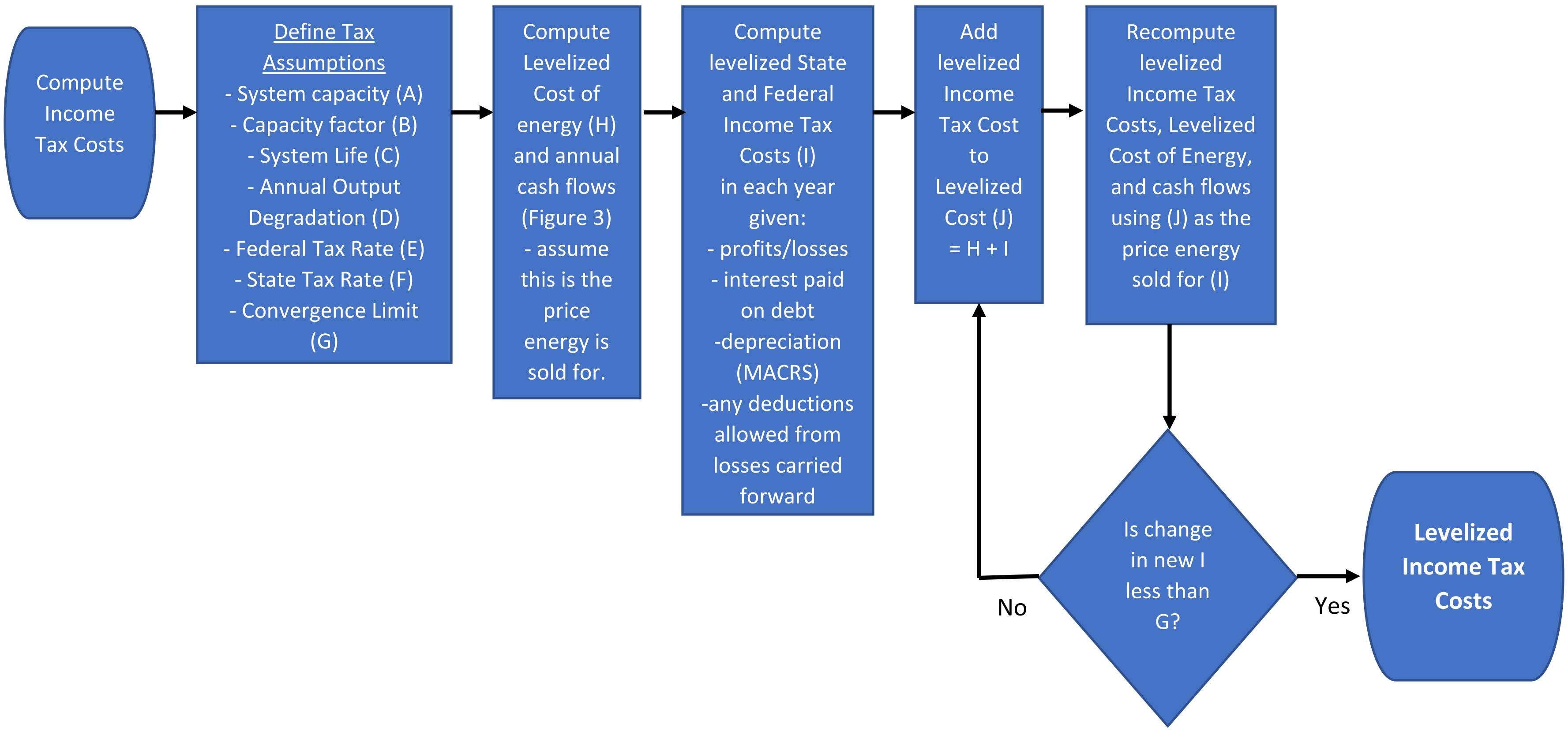


Figure A4: Gross Receipts Tax Cost Computation

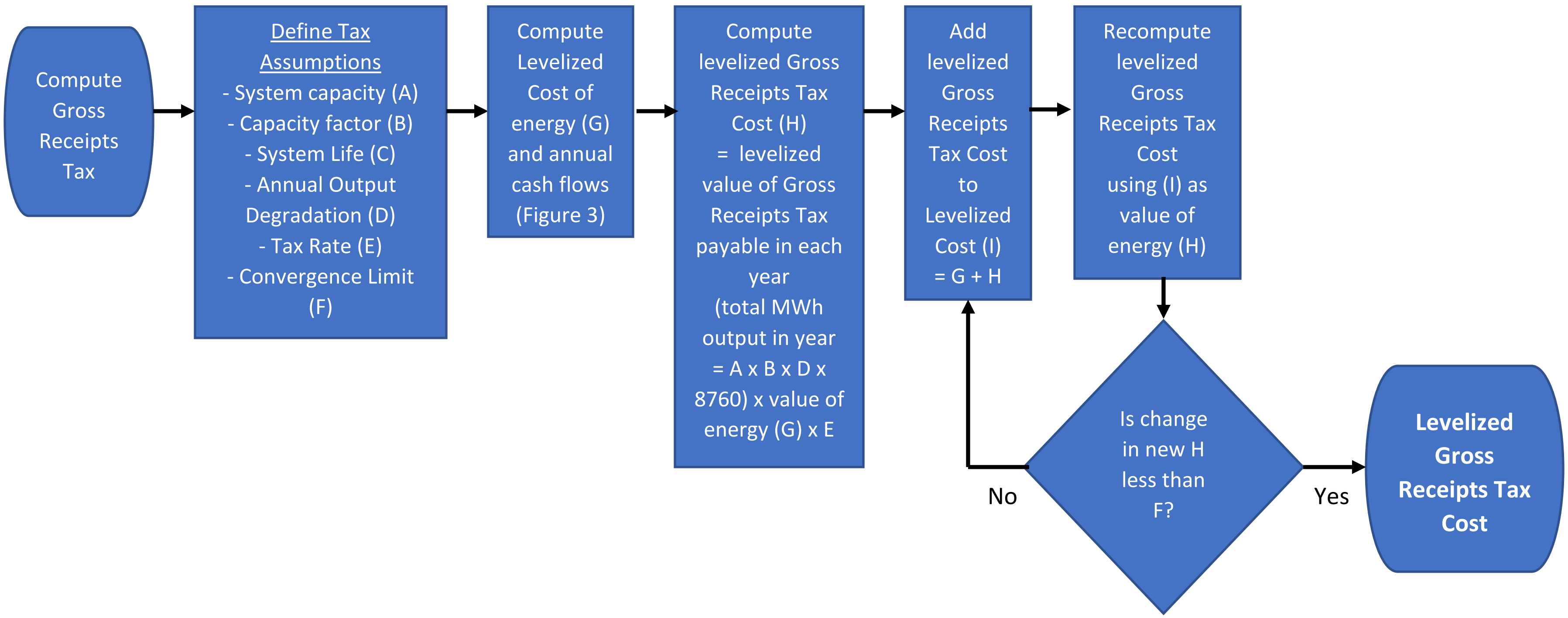


Table 1: Summary of Taxes and Incentives Applicable to Wind Projects by WECC State

	State Corporate Income Tax Rate	State Gross Receipts/ Business Tax Rate	Exemptions from Corporate or Business Taxes	Sales Tax Rate (Avg. state & local)*	Sales Tax Exemption	Property Tax Rate and Assessment Method	Property Tax Exemption/ Incentive	Depreciation Method	Specific Wind Taxes	Other Incentives/ Subsidies
Arizona	4.9%	N.A.	- None. Two programs for new generators, and self-consumption ended in 2021 and 2018, respectively.	5.6% (6.5825%)	-exemption on sales and purchase or rental of equipment to build facility over $20 million.	-assessment based on 20% of depreciated facility value	-wind equipment full cash value assessment discounted by 80%	Straightline, 20-year, 10% floor.	No	No
California	8.84%	N.A.	No	7.25% (7.99%)	-limited to non-generation equipment	- 1% tax rate on depreciated facility value	No	Straightline, 20-year, 20% floor.	No	No
Colorado	4.4%	N.A.	No	2.9% (4.15%)	-state sales tax exemption for wind facilities	- assessment based on 29% of state-adjusted expected gross revenue, taxed at 7.555%	-graduated reductions in property tax assessment for larger facilities	Straightline, 20-year, 15% floor.	No	No
Idaho	5.8%	Wind energy Production tax of 3% on gross wind energy earnings	- 3% of federally qualified investments for investment tax credits, up to 50% of tax liability	6% (6.0%)	- 25% tax rebate of all sales/use taxes paid on property constructed during project period	- Idaho exempts property of wind energy producers from taxation. In lieu of the ad valorem property tax, the Wind Energy Production Tax of 3% of producer's gross earnings is imposed.				
Montana	6.75%	N.A.	No	N.A.	-no sales tax in the state	-assessment based on 3% of depreciated facility value, taxed at 55.546% (state average)	-discount of 25% or 50% of assessed value in first 5 years, discount declines in equal increments over next 5 years until gone	Straightline, 20-year, 15% floor.	No, but state assesses a 15 cent/MWh generation tax on all generation sources	No
Nevada	N.A.	-0.136% of Nevada gross revenue exceeding $4 million	-Revenues from power exported from the state would be exempt	4.6% (7.725%)	-reduced to 2.6% on purchases in the first three years of operation	-assessment based on 35% of depreciated facility value, taxed at 3.15% (state average)	-over 10 MW, the property tax is reduced by up to 55% for up to 20 years	Straightline, 20-year, 0% floor.	No	No
New Mexico**	5.9% + $24,000 on net income over first $500,000	State: 4.875% Average across wind counties: 5.73%	- Deduction for receipts from selling facility to a government when combined with Industrial Revenue Bonds	4.875% (5.73%)	If gross receipts tax paid elsewhere, exempt from taxes applied at point of sale	-assessment based on 33.33% of depreciated facility value, taxed at 2.6666% (state average)	-taxes negotiable if industrial revenue bonding is used. 100% exemption excluding school district fees for 20 years if IRBs not used	Straightline, at 3.2% rate down to 20% floor.	No	-local industrial revenue bonding may be negotiated.
Oregon	6.6%, 7.6% on taxable income above $1 million	0.57 applied on all state sales, allowed 35% deduction for costs	No	N.A.	-no sales tax in the state	-assessment based on depreciated facility value, taxed at 1.5%	Development in rural renewable energy zones may get 3-year 100% exemption	Straightline, 20-year, 20% floor.	No	
Utah	4.65%	N.A.	- $3.50/MWh refundable production tax credit in first four years	4.85% (6.26%)	-renewable energy equipment is exempt	-assessment based on depreciated facility value, taxed at 1.3%	- abatement of some or all property taxes for projects within renewable energy development zones	Straightline, 20-year, 20% floor.	No	Economic development tax credits in enterprise zones or for significant job creation
Washington	N.A.	-Public Utility Tax: 3.8734% of gross receipts	- Can deduct sales of electricity for use outside the state	6.5% (8.1%)	- 50% to 100% exemption on new equipment and labor if project certified by Dept. of Labor and Industries	-assessment based on depreciated facility value, taxed at 1.225%	No	27-year state-specific table, 15% floor	No	No
Wyoming	N.A.	N.A.	-no taxes on income or earnings	4% (5.5%)	No	-assessment based on 11.5% of depreciated facility value, taxed at 6.8% (state average)	No	Straightline, 20-year, 20% floor.	$1/MWh	No

Table 2: State Cost Adjustment Factors

State	2023 Cost Adjustment Factor (1.00 = National Average)
AZ	0.95
CA	1.23
CO	0.93
ID	0.97
MT	0.94
NM	0.90
NV	1.08
OR	1.07
UT	0.96
WA	1.07
WY	0.93

Source: USACE (2023)

Table 3: Cost of Energy Calculation Assumptions

Cost Factor	Assumed Value
Output Capacity[a]	300 MW
Total Cap costs[a]	1511 $/kW
Share of System Costs subject to sales tax[c]	67%
Fixed O&M Annual Cost[a]	26 $/kW
Fixed O&M inflation[a]	4.5%
Variable Cost[a]	0
Cap Factor degradation rate[a]	0.75%
Construction time[b]	12 months
Facility Life[b]	20 years
Share of Financing using traditional debt[b]	60%
Cost of Debt[b]	8%
Cost of Tax-Equity[b]	10%
Cost of Direct Equity[b]	12%
Year of construction start	2022
Year of operation start	2023
Federal PTC value[d]	27.50 $/MWh
PTC inflation[e]	1.8909%
Insurance Cost[f]	0.4%
Decommissioning Cost[g]	$50,000/MW

Sources: a: DoE (2023a). Values used from the report or calculated from data within the report. b: Lazard (2023). c: Expert solicitation. d: U.S Department of Treasury (2023) assuming wage and labor criteria met. e: Federal Register, June 21, 2023. f: NREL (2013) CREST Model. g: DoE (2023a)
All values are in current dollars.

Table 4: Capacity Factors Determined for each WECC State

State	**Column A** Estimated Gross Capacity Factor Possible at top 5% of land (2014 Technology)	**Column B** Estimated Net Capacity Factor Possible at top 5% of land (2014 Technology)	**Column C** Net Capacity Factor after 20 years using 0.75% Degradation Rate
WY	56%	50.5%	43.8%
NM	56%	50.5%	43.8%
MT	56%	50.5%	43.8%
CO	55%	49.6%	43.0%
CA	46%	41.5%	36.0%
OR	45%	40.6%	35.2%
WA	45%	40.6%	35.2%
ID	45%	40.6%	35.2%
UT	42%	37.9%	32.8%
AZ	41%	37.0%	32.1%
NV	38%	34.3%	29.7%

Table 5: State Cost Components at Top 5% Capacity Factor and Including Regional Cost Differences

	Arizona	**California**	**Colorado**	**Idaho**	**Montana**	**Nevada**	**New Mexico**	**New Mexico (w/o IRB)**	**Oregon**	**Utah**	**Washington**	**Wyoming**	**Wyoming ($5 Wind Tax)**	**Wyoming (6% Royalty, No Sales or Wind Tax)**
System & Federal Taxes														
System Cost	$23.77	$27.43	$17.35	$22.11	$17.22	$29.16	$16.49	$16.49	$24.39	$23.45	$24.39	$17.04	$17.04	$17.04
Federal Tax Credits	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45
Financing Cost	$14.06	$18.98	$5.62	$11.87	$4.89	$21.10	$2.39	$4.81	$13.54	$12.40	$14.34	$5.43	$5.43	$4.67
Operating Costs	$17.48	$19.78	$12.75	$16.22	$12.58	$21.23	$12.13	$12.18	$17.62	$17.10	$17.70	$12.54	$12.54	$12.46
Federal Income Taxes	$0.01	$0.00	$0.14	$0.02	$0.12	$0.00	$0.18	$0.10	$0.00	$0.01	$0.00	$0.11	$0.09	$0.08
Pre-State Tax Total	**$45.86**	**$56.74**	**$26.40**	**$40.76**	**$25.36**	**$62.04**	**$21.74**	**$24.12**	**$46.10**	**$43.50**	**$46.98**	**$25.66**	**$25.65**	**$24.80**
State Taxes Before Incentive														
Sales Taxes (financed)	$1.05	$1.47	$0.47	$0.89	$0.00	$1.51	$0.66	$0.66	$0.00	$0.76	$1.32	$0.63	$0.63	$0.00
Property Taxes	$2.86	$4.10	$3.73	$0.00	$2.80	$3.64	$1.69	$1.73	$2.74	$2.26	$2.45	$1.36	$1.36	$1.31
State Income Tax	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$0.84	$0.00	$0.03	$1.48	$1.48	$0.00	$0.00	$0.94	$0.00	$0.00	$1.43
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.84	$4.20	$0.00
State Taxes w/o Incentives	**$3.91**	**$5.57**	**$4.20**	**$1.73**	**$2.95**	**$5.18**	**$3.83**	**$3.87**	**$2.74**	**$3.02**	**$4.71**	**$2.83**	**$6.19**	**$2.75**
State Taxes After Incentives														
Sales Taxes	$1.05	$1.47	$0.47	$0.89	$0.00	$1.51	$0.27	$0.66	$0.00	$0.00	$0.66	$0.63	$0.63	$0.00
Property Taxes	$0.72	$4.10	$0.74	$0.00	$1.63	$1.64	$0.51	$1.73	$2.19	$2.26	$2.45	$1.36	$1.36	$1.31
Income Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.74	$0.00	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$0.84	$0.00	$0.03	$1.48	$1.48	$0.00	$0.00	$0.94	$0.00	$0.00	$1.43
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.84	$4.20	$0.00
State Taxes w/ Incentives	**$1.76**	**$5.57**	**$1.21**	**$1.73**	**$1.78**	**$3.18**	**$2.25**	**$3.87**	**$2.19**	**$1.52**	**$4.05**	**$2.83**	**$6.19**	**$2.75**
Reduction in State Taxes due to Incentives	$2.15	$0.00	$2.99	$0.00	$1.16	$2.00	$1.57	$0.00	$0.55	$1.50	$0.66	$0.00	$0.00	$0.00
% Reduction in State Taxes due to Incentives	54.9%	0.0%	71.1%	0.0%	39.5%	38.6%	41.2%	0.0%	20.0%	49.8%	14.1%	0.0%	0.0%	0.0%
Average Cost of Electricity (ACOE) $/MWh	**$47.62**	**$62.30**	**$27.61**	**$42.50**	**$27.14**	**$65.22**	**$23.99**	**$27.99**	**$48.29**	**$45.02**	**$51.03**	**$28.50**	**$31.84**	**$27.55**
Assumed Capacity Factor	37.0%	41.5%	49.6%	40.6%	50.5%	34.3%	50.5%	50.5%	40.6%	37.9%	40.6%	50.5%	50.5%	50.5%
Assumed Regional Cost Difference	0.95	1.23	0.93	0.97	0.94	1.08	0.90	0.90	1.07	0.96	1.07	0.93	0.93	0.93

Table 6: State Cost Components at 35% Capacity Factor and no Regional Cost Differences

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	New Mexico (w/o IRB)	Oregon	Utah	Washington	Wyoming	Wyoming ($5 Wind Tax)	Wyoming (6% Royalty, No Sales or Wind Tax)
System & Federal Taxes														
System Cost	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43
Federal Tax Credits	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45
Financing Cost	$17.40	$17.70	$16.86	$17.28	$15.99	$17.64	$13.40	$17.27	$15.99	$15.99	$16.86	$17.17	$17.17	$15.99
Operating Costs	$19.34	$19.38	$19.29	$19.33	$19.20	$19.37	$19.25	$19.33	$19.20	$19.20	$19.29	$19.32	$19.32	$19.20
Federal Income Taxes	$0.74	$0.67	$0.73	$0.70	$0.69	$0.72	$0.71	$0.50	$0.72	$0.72	$0.64	$0.68	$0.57	$0.54
Pre-State Tax Total	**$54.46**	**$54.72**	**$53.86**	**$54.29**	**$52.86**	**$54.71**	**$50.34**	**$54.07**	**$52.89**	**$52.89**	**$53.76**	**$54.15**	**$54.03**	**$52.71**
State Taxes Before Incentive														
Sales Taxes (financed)	$1.17	$1.42	$0.72	$1.06	$0.00	$1.37	$1.05	$1.05	$0.00	$0.86	$1.43	$0.97	$0.97	$0.00
Property Taxes	$3.18	$3.95	$5.68	$0.00	$4.29	$3.30	$2.71	$2.78	$2.96	$2.55	$2.65	$2.11	$2.11	$2.04
State Income Tax	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.07	$0.00	$0.00	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.82	$0.00	$0.08	$3.33	$3.14	$0.00	$0.00	$2.17	$0.00	$0.00	$3.16
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.84	$4.20	$0.00
State Taxes w/o Incentives	**$4.35**	**$5.36**	**$6.41**	**$2.88**	**$4.44**	**$4.74**	**$7.25**	**$6.97**	**$3.04**	**$3.40**	**$6.26**	**$3.93**	**$7.29**	**$5.19**
State Taxes After Incentives														
Sales Taxes	$1.17	$1.42	$0.72	$1.06	$0.00	$1.37	$0.43	$1.05	$0.00	$0.00	$0.72	$0.97	$0.97	$0.00
Property Taxes	$0.80	$3.95	$1.05	$0.00	$2.51	$1.48	$0.81	$2.78	$2.37	$2.55	$2.65	$2.11	$2.11	$2.04
Income Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.07	-$0.74	$0.00	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.82	$0.00	$0.08	$3.33	$3.14	$0.00	$0.00	$2.17	$0.00	$0.00	$3.16
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.84	$4.20	$0.00
State Taxes w/ Incentives	**$1.96**	**$5.36**	**$1.77**	**$2.88**	**$2.66**	**$2.93**	**$4.73**	**$6.97**	**$2.44**	**$1.80**	**$5.54**	**$3.93**	**$7.29**	**$5.19**
Reduction in State Taxes due to Incentives	$2.39	$0.00	$4.63	$0.00	$1.79	$1.81	$2.52	$0.00	$0.59	$1.60	$0.72	$0.00	$0.00	$0.00
% Reduction in State Taxes due to Incentives	54.9%	0.0%	72.3%	0.0%	40.2%	38.3%	34.8%	0.0%	19.5%	47.0%	11.5%	0.0%	0.0%	0.0%
Average Cost of Electricity (ACOE) $/MWh	**$56.42**	**$60.08**	**$55.63**	**$57.17**	**$55.51**	**$57.64**	**$55.07**	**$61.04**	**$55.33**	**$54.69**	**$59.30**	**$58.08**	**$61.32**	**$57.90**
Assumed Capacity Factor	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Assumed Regional Cost Difference	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table 7: Results from eliminating Sales and Production Taxes in Wyoming and replacing them with a Royalty on Wind Generation.

	Results Assuming 6% Royalty, Sales Tax		Results under Current Wyoming Tax	
	Total Cost	**Total Cost per MWh**	**Total Cost**	**Total Cost per MWh**
System & Federal Taxes				
System Cost	$421,569,000	$17.04	$421,569,000	$17.04
Federal Tax Credits	($233,932,524)	($9.45)	($233,932,524)	($9.45)
Financing Cost	$115,615,580	$4.67	$134,394,748	$5.43
Operating Costs	$308,335,693	$12.46	$310,236,355	$12.54
Federal Income Taxes	$2,072,934	$0.08	$2,753,348	$0.11
Pre-State Tax Total	**$613,660,683**	**$24.80**	**$635,020,927**	**$25.67**
State Taxes After Incentives				
Sales Taxes	$0	$0.00	$15,534,818	$0.63
Property Taxes	$32,509,646	$1.31	$33,707,627	$1.36
Income Taxes	$0	$0.00	$0	$0.00
Royalties	$38,647,154	$1.56	$0	$0.00
Excise Taxes	$0	$0.00	$20,791,646	$0.84
State Taxes w/ Incentives	**$71,156,800**	**$2.87**	**$70,034,091**	**$2.83**
Total Cost of Electricty/ACOE	**$684,817,483**	**27.67**	**$705,055,018**	**$28.50**
Megawatt Hours Produced (20 years)		24,742,845		24,742,845

Endnotes

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[i] See, for example, the wind capacity projections in the U.S. Energy Information Agency (EIA) Annual Energy Outlook (2023).

[ii] These benefits have been documented in numerous studies using several methodologies including econometric studies (e.g. Brown et al., 2012), input-output methods (e.g. Slattery et al., 2011, Godby et. al., 2016), and case study approaches (e.g. Pedden, 2006).

[iii] Outside of the academic literature, only two such cost studies exist to our knowledge. See E3, 2010; and Cook and Godby, 2019.

[iv] We limit our comparison to WECC-states. While it is the case that power from states in the WECC may provide power to states in the Eastern Interconnection, or to the Electric Reliability Council of Texas (ERCOT), power transfer capability from western states is limited, and we assume these regions are separate electricity markets.

[v] Many but not all these studies have controlled for non-policy factors such as local wind resource and transmission access, both of which have also been found to positively influence wind development.

[vi] The oldest federal policy that has indirectly incentivized wind development in the west has been the Public Utility Regulatory Policies Act of 1978 (PURPA), which affects only utility markets. In the WECC, all states except California are still regulated. California competitively restructured most of its electricity market in 1998. PURPA typically requires regulated utilities to accept power generated from qualifying facilities that are typically 80 MW in capacity or less, at the utility's avoided cost of energy as determined by state regulators. Contracts are fixed length, often 20 years. State policy can affect wind project profitability through modification to rules governing PURPA-qualifying facilities. States may modify avoided cost rates, allowing price schedules that are more or less favorable to renewable energy developers. States may also reduce the length of time that PURPA contracts are binding. They may even modify the size of facilities that may be considered as qualifying under PURPA. See Black et al, 2014 for the case of Idaho, which has enacted all three types of changes to affect wind development. Such rule changes may in part explain why Idaho has not seen new wind development since 2012 (see Figure 3) despite having a competitive potential wind resource (see Figure 5).

[vii] Her results suggested in some specifications that the effect of property tax incentives may even be negative.

[viii] In Pinky et al. (2023) the presence of various tax incentives was accounted for by dummy variable only, without consideration of relative differences in the level of tax incentives across counties and states.

[ix] Capacity factor is a measure of wind resource, describing the percentage of total production capacity achieved at a site. For greater detail see the notes in the Appendix.

[x] While all but two states (California and Idaho) are net exporters of electricity, Wyoming, Montana, and New Mexico are the largest exporters of electricity in the WECC. Wyoming consumes only 35.6% of electricity generated, while Montana consumes 57.5% and New Mexico 66.4% (calculated based on in-state annual retail sales as a share of total net generation in each state - see EIA, 2022 State Electricity Profiles https://www.eia.gov/electricity/state/)

[xi] Among the top-performing states in the WECC, Wyoming is an example of how technological improvements interact with transmission capacity improvements to increase average capacity factors. While potential capacity factors are similar across all four eastern WECC states (MT, WY, CO, and NM), realized capacity factor in Wyoming was below the national average and below the other three eastern WECC states in 2019 and 2020. In 2018, Wyoming's largest wind generation owner, PacifiCorp began a transmission upgrade plan to facilitate additional wind development and better operations in the state. Transmission improvements allowed wind facilities to avoid curtailment – operational shutdowns – that occur when grid capacity is lacking to accept production. A combination of efforts to improve productivity at wind sites, investments in transmission capacity, and declines in the transmission of coal-fueled electricity (freeing up transmission capacity for wind-generated electricity) helped cause Wyoming's average capacity factor improvement in 2021 and 2022 evident in Figure 5.

[xii] In the case of CC/SM project, the 732-mile TransWest line will cross Wyoming, Colorado, Utah, and Nevada before terminating near the California border. The 550-mile SunZia line will link central New Mexico with south-central Arizona. SunZia is scheduled to begin operation in 2026 while CC/SM and TransWest are anticipated to begin operations in 2027.

[xiii] The Federal Business Energy Investment Tax Credit (ITC) program allows large wind projects to apply for a tax rebate based on the value of equipment. The current law was extended to 2024 by passage of the IRA and allows a 30% rebate for projects beginning construction before January 1, 2025. In 2025, the tax credits will be phased out and replaced with technology-neutral credits for low-carbon electricity generation. These new credits will be phased out by 2032 or when the US power sector reduces greenhouse gas emissions to 25% of 2022 levels, whichever is later. The Federal Renewable Electricity Production Tax Credit allowed a credit against federal taxes of $23/MWh of production to be earned in 2016, declining in 20% increments and adjusted for inflation through the years 2017, 2018 and 2019 before ending in 2020, with projects begun in 2019 required to be online by 2021 to avoid risking the loss of the credit. This was also extended by the passage of the IRA and, like ITCs, will be replaced by low-carbon electricity generation credits in 2025.

[xiv] In April 2023, the IRS released details on the specific definition of an energy community, which includes brownfield sites, coal communities, and areas with a specific mix of employment and local tax revenue related to current or past fossil energy activity. See https://www.irs.gov/pub/irs-drop/n-23-29.pdf.

[xv] Wind developers typically have little or no federal tax liability due to the deductibility of interest paid on debt used to finance the large capital costs involved, capital depreciation cost deductions, and the allowance to carry forward operating losses from previous years against taxes owed.

[xvi] Research has also shown that production tax credits incentivize greater productivity at wind facilities (see Aldy et al, 2019). Given tax benefits sold as a form of equity finance require production to be realized, this finding is perhaps unsurprising.

[xvii] Technically, Minnesota also assesses a $1.20 per MWh generation tax on wind facilities larger than 12 MW in capacity, however, the tax is imposed in lieu of assessing property taxes on the improved value of the land.

[xviii] Such financing lowers cost of debt as it is issued by a county or municipal agency.

[xix] Technically it may be possible for other states to use similar bonding practice. For example, Wyoming law could allow such bonding for large wind and other capital projects. To date, however, only New Mexico has made this opportunity widely available for wind development.

[xx] Joskow (2011) notes that the use of levelized cost to compare intermittent technologies like wind generation to traditional dispatchable technologies can be misleading because the value of electricity produced varies over time. Criticisms of common levelized cost estimates include that they do not distinguish between capital, fixed and marginal costs, that results are sensitive to assumed interest rates and assumed project lifetimes and if/how discounting is applied to the calculation, that such measures ignore project or technology-specific risk factors and externalities, and that the metric usually ignores any integration costs.

[xxi] We use “average cost of energy” to differentiate our results that include incentive, regional wind resource, and cost considerations from other estimates that are computed differently, such as Lazard (2023). Given the difference between our computation methods and others presented in the literature or by industry, absolute cost estimates are also not directly comparable to those presented elsewhere. All dollar values are unadjusted for inflation.

[xxii] We admit that cost estimates presented overlook time of day or seasonal generation profiles that could affect the relative value of generation across states or locations and that differences in regional integration costs in the west and other factors could affect project location decisions.

[xxiii] It is important to note that the cost estimates developed here do not include any additional costs necessary to complete local permitting or transmission development.

[xxiv] Hitaj (2013) presumes all system costs are taxable. Some purchases, however, may occur in other states or be exempt under state law.

[xxv] Nevada and California are the exception. For Nevada, the net capacity factor at the top 5% of the land is less than 35 percent (Table 5, Column B) thus using a state-specific capacity factor defines the upper ACOE limit for this state. For California, though the state-specific capacity factor of 41.3 percent (Table 5, Column B) is greater than 35

percent, because the state-specific construction cost difference is so much higher than the other WECC states see Table 2), the upper ACOE limit is defined by the computation using state-specific factors.

[xxvi] In our research, we could not find a recent wind project in New Mexico that did not use IRBs, and the alternative is shown for completeness.

[xxvii] This conclusion is consistent with some of the findings in Hitaj (2013), however, she considers only corporate tax credits. She does not consider income taxes specifically, but all corporate taxes. General studies of corporate income and business tax impacts also show little negative impact (see Gale et al., 2015).

[xxviii] Her data did not include Wyoming, as the tax came into effect after 2007, the terminal date of her dataset.

[xxix] Some of the relative advantage ACOE New Mexico gains over Wyoming occurs due to regional costs in New Mexico being 3.2 percent lower than Wyoming's (capacity factors are assumed the same across both states).

[xxx] Recall that while Wyoming assesses a $1/MWh production tax, it is not implemented until after the project has operated for 3 years, and this, combined with assumed productivity decline over time, results in an average cost of $0.84/MWh.

[xxxi] In 2009, Wyoming considered a royalty of 3 percent assessed on the value of wind generation in the state. See House Bill 275 "Wind Turbines Royalty Fee", and Madden (2019) for a description.

[xxxii] We assume direct equity is financed as an annuity payable over the life of the project and returning the rate of return assumed on direct equity shown in Table 4.

[xxxiii] In a traditional levelized cost computation, costs over time are the costs and production of the facility in each year would be discounted using an assumed discount rate. Other estimates of levelized costs, however, including influential estimates like those produced annually by Lazard (2023), ignore discounting to derive results. We follow the latter approach for several reasons. First, it eases transparency and clarity of the results by making dollar values comparable across years. Second, while standard microeconomic arguments assume agent time preferences, we use our computations to estimate potential government revenues under various taxation strategies. It is not clear government time preferences are consistent with individual agents' or firms' due to two realities local and state governments face. In some cases, governments may have budgetary rules that make banking unspent revenues for use later difficult, and there can be very real political consequences such banking may create. For example, a municipal leader banking unspent revenues invites political challenges from anti-tax opponents who may argue for a lower-tax platform based on the premise that such savings prove that taxes are higher than necessary. Often when asked, public leaders will admit that they value streams of payments over much larger one-time lump sum payments because they make sustainable budgeting easier to plan. Such realities in local government undermine the argument for using discounted values because discounting implicitly implies a time preference argument exists, which may not be true, at least in the case of local government revenue options.

[xxxiv] Federal depreciation is computed using the MACRS method, and state depreciation and incentives computed as specified in Table 2. For federal taxes, up to 80% of any annual losses recorded are carried forward and deducted against future income, consistent with Federal tax rules.

[xxxv] GCF refers to the share of total potential power a specific turbine design would be expected to achieve given the wind resource in a location relative to the maximum potential power the turbine could produce if it were able to always generate at its maximum rated power. GCF does not include adjustment for reduction in output due to operational considerations or turbine interactions. When such adjustments are considered, the result is referred to as the net capacity factor (NCF). NREL (2015) assumed then-current wind generation technology used towers 110m in height. Earlier technologies used 80m towers, while near future technologies assume 140m hub-heights and 110m blade diameters. National rankings are shown with respect to "near future" technology as this is more descriptive of the technological advancements deployed today versus when the table was first created by NREL.

[xxxvi] See the "Cumulative Area vs. Gross Capacity Factor" charts available for each state at the WindExchange website (Wind Energy Maps and Data section) https://windexchange.energy.gov/maps-data, accessed September 18, 2023).

[xxxvii] These include a 4% adjustment factor for wind farm wake effects (turbine wake interference with other wind turbines), a 1% reduction for high winds or extreme temperatures that require turbines to shut down, a 2% reduction for electrical efficiency losses, and 0.5% reduction for consumptive power losses necessary to maintain operation of the wind turbines. These are consistent with losses used in industry. See for example (Vaisala, 2016).

The product of the availabilities implied by these factors is 0.901636, and this multiplier was used to reduce GCF to net values.

[xxxviii] This rounded value was computed using a simple trend from capacity factor data contained in DoE (2023).

[xxxix] States that are relatively farther from the largest markets or load centers may incur greater costs to develop necessary transmission and interconnection infrastructure to deliver power to market (Hitaj, 2013, and Godby, Taylor and Coupal, 2016). Several industry transmission planning reports and academic studies have discussed the need for greater transmission development if wind generation in the west is to be developed on much larger scales than seen today (see for example: GE Energy, 2010; and Godby, Torell and Coupal, 2014, Larson et al., 2021). Permitting transmission can be very costly and require tedious local, state, and federal permitting processes, thereby delaying wind development and increasing project cost. These concerns seem validated by the experience of two very large wind developments in the west; the Power Company of Wyoming's Chokecherry and Sierra Madre project (3000 MW) and TransWest Transmission line, and the SunZia project (3500 MW) in New Mexico. Both projects have estimated total costs of $8 billion, with the transmission share of costs as high as $3 billion. Both projects began permitting processes in the middle of the last decade (2007 and 2006 respectively), and both only received final permit approvals in 2023, despite both being "fast-tracked" infrastructure projects by the Obama Administration in 2014. Estimating factors affecting state and regional permitting cost differences is a largely unexplored area in academic research and we do not attempt such estimates here.